

IEEE **violet** BOOK™



551™

IEEE Recommended Practice for

**Calculating
Short-Circuit
Currents in
Industrial and
Commercial
Power Systems**

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IEEE Recommended Practice for Calculating Short-Circuit Currents in Industrial and Commercial Power Systems

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of the
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Abstract: This recommended practice provides short-circuit current information including calculated short-circuit current duties for the application in industrial plants and commercial buildings, at all power system voltages, of power system equipment that senses, carries, or interrupts short-circuit currents. Equipment coverage includes, but should not be limited to, protective device sensors such as series trips and relays, passive equipment that may carry short-circuit current such as bus, cable, reactors and transformers as well as interrupters such as circuit breakers and fuses.

Keywords: available fault current, circuit breaker, circuit breaker applications, fuse, power system voltage, reactors, short-circuit applications guides, short-circuit duties

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Introduction

This introduction is not part of IEEE Std 551-2006, IEEE Recommended Practice for Calculating Short-Circuit Currents in Industrial and Commercial Power Systems.

This recommended practice is intended as a practical, general treatise for engineers on the subject of ac short-circuit currents in electrical power systems. The focus of this standard is the understanding and application of analytical techniques of short-circuit analysis in industrial and commercial power systems. However, the same engineering principles apply to all electrical power systems, including utilities and systems other than 60 Hz.

More than any other book in the IEEE Color Book® series, the “Violet Book” covers the basics of short-circuit currents. To help the reader, the same one-line diagram that is used in several of the other color books is used in sample calculations. Items covered in the Violet Book that are not covered in the other color book chapters on short-circuit currents are the contributions of regenerative SCR drives and capacitors to faults. The reference data chapter in this recommended practice is quite extensive and should be very useful for any type of power system analysis.

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IEEE Recommended Practice for Calculating Short-Circuit Currents in Industrial and Commercial Power Systems

Chapter 1 Introduction

1.1 Scope

Electric power systems in industrial plants and commercial and institutional buildings are designed to serve loads in a safe and reliable manner. One of the major considerations in the design of a power system is adequate control of short circuits or faults as they are commonly called. Uncontrolled short-circuits can cause service outage with accompanying production downtime and associated inconvenience, interruption of essential facilities or vital services, extensive equipment damage, personnel injury or fatality, and possible fire damage.

Short-circuits are caused by faults in the insulation of a circuit, and in many cases an arc ensues at the point of the fault. Such an arc may be destructive and may constitute a fire hazard. Prolonged duration of arcs, in addition to the heat released, may result in transient overvoltages that may endanger the insulation of equipment in other parts of the system. Clearly, the fault must be quickly removed from the power system, and this is the job of the circuit protective devices—the circuit breakers and fusible switches.

A short-circuit current generates heat that is proportional to the square of the current magnitude, I^2R . The large amount of heat generated by a short-circuit current may damage the insulation of rotating machinery and apparatus that is connected into the faulted system, including cables, transformers, switches, and circuit breakers. The most immediate danger involved in the heat generated by short-circuit currents is permanent destruction of insulation. This may be followed by actual fusion of the conducting circuit, with resultant additional arcing faults.

The heat that is generated by high short-circuit currents tends not only to impair insulating materials to the point of permanent destruction, but also exerts harmful effects upon the contact members in interrupting devices.

The small area common between two contact members that are in engagement depends mainly upon the hardness of the contact material and upon the amount of pressure by which they are kept in engagement. Owing to the concentration of the flow of current at the points of contact engagement, the temperatures of these points reached at the times of peak current are very high. As a result of these high spot temperatures, the material of which the contact members are made may soften. If, however, the contact material is caused to melt by excessive I^2R losses, there is an imminent danger of welding the contacts together rendering it impossible to separate the contact members when the switch or circuit breaker is called upon to open the circuit. Since it requires very little time to establish thermal equilibrium at the small points of contact engagement, the temperature at these points depends more upon the peak current than upon the rms current. If the peak current is sufficient to cause the contact material to melt, resolidification may occur immediately upon decrease of the current from its peak value.

Other important effects of short-circuit currents are the strong electromagnetic forces of attraction and repulsion to which the conductors are subjected when short-circuit currents are present. These forces are proportional to the square of the current and may subject any rotating machinery, transmission, and switching equipment to severe mechanical stresses and strains. The strong electromagnetic forces that high short-circuit currents exert upon equipment can cause deformation in rotational machines, transformer windings, and equipment bus bars, which may fail at a future time. Deformation in breakers and switches will cause alignment and interruption difficulties.

Modern interconnected systems involve the operation in parallel of large numbers of synchronous machines, and the stability of such an interconnected system may be greatly impaired if a short-circuit in any part of the system is allowed to prevail. The stability of a system requires short fault clearing times and can be more limiting than the longer time considerations imposed by thermal or mechanical effects on the equipment.

1.2 Definitions

For the purpose of this document, the following terms and definitions apply. *The Authoritative Dictionary of IEEE Standards Terms* [B3]¹ should be referenced for terms not defined in this clause.

1.2.1 30 cycle time: The time interval between the time when the actuating quantity of the release circuit reaches the operating value, and the approximate time when the primary arcing contacts have parted. The time period considers the ac decaying component of a fault current to be negligible.

¹The numbers in brackets correspond to those of the bibliography in 1.4.

1.2.2 arcing time: The interval of time between the instant of the first initiation of the arc and the instant of final arc extinction in all poles.

1.2.3 armature: The main current carrying winding of a machine, usually the stator.

1.2.4 armature resistance: R_a —The direct current armature resistance. This is determined from a dc resistance measurement. The approximate effective ac resistance is $1.2R_a$.

1.2.5 asymmetrical current: The combination of the symmetrical component and the direct current component of the current.

1.2.6 available current: The current that would flow if each pole of the breaking device under consideration were replaced by a link of negligible impedance without any change of the circuit or the supply.

1.2.7 breaking current: The current in a pole of a switching device at the instant of the arc initiation. Better known as *interrupting current*.

1.2.8 circuit breaker: A switching device capable of making, carrying, and breaking currents under normal circuit conditions and also making, carrying for a specified time, and breaking currents under specified abnormal conditions such as those of short circuit.

1.2.9 clearing time: The total time between the beginning of specified overcurrent and the final interruption of the circuit at rated voltage. In regard to fuses, it is the sum of the minimum melting time of a fuse plus tolerance and the arcing time. In regard to breakers under 1000 V, it is the sum of the sensor time, plus opening time and the arcing time. For breakers rated above 1000 V, it is the sum of the minimum relay time (usually 1/2 cycle), plus contact parting time and the arcing time. Sometimes referred to as *total clearing time* or *interrupting time*.

1.2.10 close and latch: The capability of a switching device to close (allow current flow) and immediately thereafter latch (remain closed) and conduct a specified current through the device under specified conditions.

1.2.10.1 close and latch duty: The maximum rms value of calculated short-circuit current for medium- and high-voltage circuit breakers during the first cycle with any applicable multipliers for fault current X/R ratio. Often the close and latching duty calculation is simplified by applying a 1.6 factor to the calculated breaker first cycle symmetrical ac rms short-circuit current. Also called first cycle duty (formerly, momentary duty).

1.2.10.2 close and latch rating: The maximum current capability of a medium or high-voltage circuit breaker to close and immediately thereafter latching closed for normal-frequency making current. The close and latching rating is 1.6 times the breaker rated maximum symmetrical interrupting current in ac rms amperes or a peak current that is 2.7 times ac rms rated maximum symmetrical interrupting current. Also called first cycle rating (formerly, momentary rating).

1.2.11 contact parting time: The interval between the time when the actuating quantity in the release circuit reaches the value causing actuation of the release and the instant when the primary arcing contacts have parted in all poles. Contact parting time is the numerical sum of release delay and opening time.

1.2.12 crest current: The highest instantaneous current during a period. *Syn:* **peak current.**

1.2.13 direct axis: The machine axis that represents a plane of symmetry in line with the no-load field winding.

1.2.14 direct axis subtransient reactance: X'_{dv} (saturated, rated voltage) is the apparent reactance of the stator winding at the instant short-circuit occurs with the machine at rated voltage, no load. This reactance determines the current flow during the first few cycles after short-circuit.

1.2.15 direct axis subtransient reactance: X'_{di} (unsaturated, rated current) is the reactance that is determined from the ratio of an initial reduced voltage open circuit condition and the currents from a three-phase fault at the machine terminals at rated frequency. The initial open-circuit voltage is adjusted so that rated current is obtained. The impedance is determined from the currents during the first few cycles.

1.2.16 direct axis transient reactance: X'_{dv} (saturated, rated voltage) is the apparent reactance of the stator winding several cycles after initiation of the fault with the machine at rated voltage, no load. The time period for which the reactance may be considered X'_{dv} can be up to a half (1/2) second or longer, depending upon the design of the machine and is determined by the machine direct-axis transient time constant.

1.2.17 direct axis transient reactance: X'_{di} (unsaturated, rated current) is the reactance that is determined from the ratio of an initial reduced voltage open circuit condition and the currents from a three-phase fault at the machine terminals at rated frequency. The initial open-circuit voltage is adjusted so that rated current is obtained. The initial high decrement currents during the first few cycles are neglected.

1.2.18 fault: A current that flows from one conductor to ground or to another conductor owing to an abnormal connection (including an arc) between the two. *Syn:* **short circuit.**

1.2.19 fault point angle: The calculated fault point angle ($\tan^{-1}(X/R)$ ratio) using complex ($R + jX$) reactance and resistance networks for the X/R ratio.

1.2.20 fault point X/R : The calculated fault point X/R ratio using separate reactance and resistance networks.

1.2.21 field: The exciting or magnetizing winding of a machine.

1.2.22 first cycle duty: The maximum value of calculated short-circuit current for the first cycle with any applicable multipliers for fault current X/R ratio.

1.2.23 first cycle rating: The maximum current capability of a piece of equipment during the first cycle of a fault.

1.2.24 frequency: The rated frequency of a circuit.

1.2.25 fuse: A device that protects a circuit by melting open its current-carrying element when an overcurrent or short-circuit current passes through it.

1.2.26 high voltage: Circuit voltages over nominal 34.5 kV.

NOTE—ANSI standards are not unanimous in establishing the threshold of “high-voltage.”²

1.2.27 impedance: The vector sum of resistance and reactance in an ac circuit.

1.2.28 interrupting current: The current in a pole of a switching device at the instant of the arc initiation. Sometime referred to as *breaking current*.

1.2.29 interrupting time: The interval between the time when the actuating device “sees” or responds to a operating value, the opening time and arcing time. Sometimes referred to as *total break time* or *clearing time*.

1.2.30 low voltage: Circuit voltage under 1000 V.

1.2.31 maximum rated voltage: The upper operating voltage limit for a device.

1.2.32 medium voltage: Circuit voltage greater than 1000 V up to and including 34.5 kV.

NOTE—ANSI standards are not unanimous in establishing the threshold of “high-voltage.”

1.2.33 minimum rated voltage: The lower operating voltage limit for a device where the rated interrupting current is a maximum. Operating breakers at voltages lower than minimum rated voltage restricts the interrupting current to maximum rated interrupting current.

1.2.34 momentary current rating: The maximum rms current measured at the major peak of the first cycle, which the device or assembly is required to carry. Momentary rating was used on medium- and high-voltage breakers manufactured before 1965. See presently used terminology of **close and latch rating**.

1.2.35 momentary current duty: See presently used terminology of **close and latch duty**. Used for medium- and high-voltage breaker duty calculations for breakers manufactured before 1965.

1.2.36 negative sequence: A set of symmetrical components that have the angular phase lag from the first member of the set to the second and every other member of the set equal to the characteristic angular phase difference and rotating in the reverse direction of the

²Notes in text, tables, and figures are given for information only and do not contain requirements needed to implement the standard.

original vectors. For a three-phase system, the angular different is 120 degrees. *See also: symmetrical components.*

1.2.37 negative sequence reactance: X_{2v} (saturated, rated voltage). The rated current value of negative-sequence reactance is the value obtained from a test with a fundamental negative-sequence current equal to rated armature current (of the machine). The rated voltage value of negative-sequence reactance is the value obtained from a line-to-line short-circuit test at two terminals of the machine at rated speed, applied from no load at rated voltage, the resulting value being corrected when necessary for the effect of harmonic components in the current.

1.2.38 offset current: A current waveform whose baseline is offset from the ac symmetrical current zero axis.

1.2.39 opening time: The time interval between the time when the actuating quantity of the release circuit reaches the operating value, and the instant when the primary arcing contacts have parted. The opening time includes the operating time of an auxiliary relay in the release circuit when such a relay is required and supplied as part of the switching device.

1.2.40 peak current: The highest instantaneous current during a period.

1.2.41 positive sequence: A set of symmetrical components that have the angular phase lag from the first member of the set to the second and every other member of the set equal to the characteristic angular phase difference and rotating in the same phase sequence of the original vectors. For a three-phase system, the angular different is 120 degrees. *See also: symmetrical components.*

1.2.42 positive sequence machine resistance: R_1 is that value of rated frequency armature resistance that, when multiplied by the square of the rated positive-sequence armature current and by the number of phases, is equal to the sum of the copper loss in the armature and the load loss resulting from the flow of that current. This is **NOT** the resistance to be used for the machine in short-circuit calculations.

1.2.43 quadrature axis: The machine axis that represents a plane of symmetry in the field that produces no magnetization. This axis is 90 degrees ahead of the direct axis.

1.2.44 quadrature axis subtransient reactance: X''_{qv} (saturated, rated voltage) same as X''_{dv} except in quadrature axis.

1.2.45 quadrature axis subtransient reactance: X''_{qi} (unsaturated, rated current) same as X''_{di} except in quadrature axis.

1.2.46 quadrature axis transient reactance: X'_q (unsaturated, rated current) is the ratio of reactive armature voltage to quadrature-axis armature current at rated frequency and voltage.

1.2.47 quadrature axis transient reactance: X'_{qv} (saturated, rated voltage) same as X'_{dv} except in q quadrature axis.

1.2.48 quadrature axis transient reactance: X'_{qi} (unsaturated, rated voltage) same as X'_{di} except in quadrature axis.

1.2.49 rating: The designated limit(s) of the operating characteristic(s) of a device. This data is usually on the device nameplate.

1.2.50 rms: The square root of the average value of the square of the voltage or current taken throughout one period. In this text, rms will be considered total rms unless otherwise noted.

1.2.51 rms ac: The square root of the average value of the square of the ac voltage or current taken throughout one period.

1.2.52 rms, single cycle: *See: single-cycle rms.*

1.2.53 rms, total: *See: total rms.*

1.2.54 rotor: The rotating member of a machine.

1.2.55 short circuit: An abnormal connection (including arc) of relative low impedance, whether made accidentally or intentionally, between two points of different potentials.
Syn: fault.

1.2.56 short-circuit duty: The maximum value of calculated short-circuit current for either first cycle current or interrupting current with any applicable multipliers for fault current X/R ratio or decrement.

1.2.57 single-cycle rms: The square root of the average value of the square of the ac voltage or current taken throughout one ac cycle.

1.2.58 stator: The stationary member of a machine.

1.2.59 symmetrical: That portion of the total current that, when viewed as a waveform, has equal positive and negative values over time such as is exhibited by a pure single-frequency sinusoidal waveform

1.2.60 symmetrical components: A symmetrical set of three vectors used to mathematically represent an unsymmetrical set of three-phase voltages or currents. In a three-phase system, one set of three equal magnitude vectors displaced from each other by 120 degrees in the same sequence as the original set of unsymmetrical vectors. This set of vectors is called the positive sequence component. A second set of three equal magnitude vectors displaced from each other by 120 degrees in the reverse sequence as the original set of unsymmetrical vectors. This set of vectors is called the negative sequence component. A third set of three equal magnitude vectors displaced from each other by 0 degrees. This set of vectors is called the zero sequence component.

1.2.61 synchronous reactance: Direct axis X_d (unsaturated, rated current) is the self reactance of the armature winding to the steady-state balanced three-phase positive-sequence current at rated frequency and voltage in the direct axis. It is determined from an initial open-circuit voltage and a sustained short circuit on the a synchronous machine terminals.

1.2.62 three-phase open circuit time constant: T_{a3} is the time constant representing the decay of the machine currents to a suddenly applied three-phase short-circuit to the terminals of a machine.

1.2.63 total break time: The interval between the time when the actuating quantity of the release circuit reaches the operating value, the switching device being in a closed position, and the instant of arc extinction on the primary arcing contacts. Total break time is equal to the sum of the opening time and arcing time. Better known as **interrupting time**.

1.2.64 total clearing time: *See: clearing time or interrupting time.*

1.2.65 total rms: The square root of the average value of the square of the ac and dc voltage or current taken throughout one period.

1.2.66 voltage, high: *See: high voltage.*

1.2.67 voltage, low: *See: low voltage.*

1.2.68 voltage, medium: *See: medium voltage.*

1.2.69 voltage range factor: The voltage range factor, K , is the range of voltage to which the breaker can be applied where EI equals a constant. K equals the maximum rated operating voltage divided by the minimum rated operating voltage.

1.2.70 X/R ratio: The ratio of rated frequency reactance and effective resistance to be used for short-circuit calculations. Approximately equal to $X_{2v}/1.2R_a$ or $2fT_{a3}$.

1.2.71 zero sequence: A set of symmetrical components that have the angular phase lag from the first member of the set to the second and every other member of the set equal to zero (0) degrees and rotating in the same direction as the original vectors. *See also: symmetrical components.*

1.3 Acronyms and abbreviations

The following are the symbols and their definitions that are used in this book.

a	symmetrical component operator = 120 degrees
e	instantaneous voltage
e_0	initial voltage

E	rms voltage
E_{\max}	peak or crest voltage
E_{LN}	rms line-to-neutral voltage
E_{LL}	rms line-to-line voltage
f	frequency in Hertz
i	instantaneous current
i_{dc}	instantaneous dc current
i_{ac}	instantaneous ac current
I	rms current
I_{\max}	peak or crest current
$I_{\max,\text{s}}$	symmetrical peak current
$I_{\max,\text{ds}}$	decaying symmetrical peak current
I'	rms transient current
I''	rms subtransient current
I'_{dd}	interrupting duty current
I''_{dd}	first cycle duty current
I_{SS}	rms steady state current
j	90 degree rotative operator, imaginary unit
L	inductance
Q	electric charge
R	resistance
R_{a}	armature resistance
t	time
T_{a3}	three-phase open-circuit time constant

X	reactance
X_d'	transient direct-axis reactance
X_d''	subtransient direct-axis reactance
X_q'	transient quadrature-axis reactance
X_q''	subtransient quadrature-axis reactance
X_{2v}	negative sequence rated voltage
Z	impedance: $Z = R + jX$
α	$\tan^{-1}(\omega L/R) = \tan^{-1}(X/R)$
ϕ	phase angle
ω	angular frequency $\omega = 2\pi f$
τ	intermediate time
θ	phase angle difference

1.4 Bibliography

The IEEE publishes several hundred standards documents covering various fields of electrical engineering. Appropriate IEEE standards are routinely submitted to the American National Standards Institute (ANSI) for consideration as ANSI-approved standards. Standards that have also been submitted and approved by the Canadian Standards Association carry CSA letters. Basic standards of general interest include the following:

[B1] ANSI/IEEE Std 91TM-1984, *IEEE Standard Graphic Symbols for Logic Diagrams*.³

[B2] ANSI 268-1992, *American National Standard Metric Practice*.

[B3] IEEE 100, *The Authoritative Dictionary of IEEE Standards Terms*, Seventh Edition.^{4, 5}

³ANSI publications are available from the Sales Department, American National Standards Institute, 25 West 43rd Street, 4th Floor, New York, NY 10036, USA (<http://www.ansi.org/>).

⁴IEEE publications are available from the Institute of Electrical and Electronics Engineers, 445 Hoes Lane, P.O. Box 1331, Piscataway, NJ 08855-1331, USA (<http://standards.ieee.org/>).

⁵The IEEE standards or products referred to in this clause are trademarks of the Institute of Electrical and Electronics Engineers, Inc.

[B4] IEEE Std 260.1™-2004, IEEE Standard Letter Symbols for Units of Measurement (SI Units, Customary Inch-Pound Units, and Certain Other Units).

[B5] IEEE Std 280™-1985 (Reaff 2003), IEEE Standard Letter Symbols for Quantities Used in Electrical Science and Electrical Engineering.

[B6] IEEE Std 315™-1975 (Reaff 1993)/ANSI Y32.2-1975 (Reaff 1989) (CSA Z99-1975), IEEE Standard for Graphic Symbols for Electrical and Electronics Diagrams.

The IEEE publishes several standards documents of special interest to electrical engineers involved with industrial plant electric systems, which are sponsored by the Power Systems Engineering Committee of the IEEE Industry Applications Society:

[B7] IEEE Std 141™-1993, IEEE Recommended Practice for Electric Power Distribution of Industrial Plants (*IEEE Red Book*).

[B8] IEEE Std 142™-1991, IEEE Recommended Practice for Grounding of Industrial and Commercial Power Systems (*IEEE Green Book*).

[B9] IEEE Std 241™-1990, IEEE Recommended Practice for Electric Power Systems in Commercial Buildings (*IEEE Gray Book*).

[B10] IEEE Std 242™-2001, IEEE Recommended Practice for Protection and Coordination of Industrial and Commercial Power Systems (*IEEE Buff Book*).

[B11] IEEE Std 399™-1997, IEEE Recommended Practice for Power Systems Analysis (*IEEE Brown Book*).

[B12] IEEE Std 446™-1995, IEEE Recommended Practice for Emergency and Standby Power Systems for Industrial and Commercial Applications (*IEEE Orange Book*).

[B13] IEEE Std 493™-1997, IEEE Recommended Practice for the Design of Reliable Industrial and Commercial Power Systems (*IEEE Gold Book*).

[B14] IEEE Std 602™-1996, IEEE Recommended Practice for Electric Systems in Health Care Facilities (*IEEE White Book*).

[B15] IEEE Std 739™-1995, IEEE Recommended Practice for Energy Management in Industrial and Commercial Facilities (*IEEE Bronze Book*).

[B16] IEEE Std 1100™-2005, IEEE Recommended Practice for Powering and Grounding Sensitive Electronic Equipment (*IEEE Emerald Book*).

1.5 Manufacturers' data sources

The last chapter in this reference book contains a collection of data from various manufacturers. While reasonable care was used compile this data, equipment with the

same identification and manufactured during different periods may have different ratings. The equipment nameplate is the best source of data and may require obtaining the serial number and contacting the manufacturer.

The electrical industry, through its associations and individual manufacturers of electrical equipment, issues many technical bulletins and data books. While some of this information is difficult for the individual to obtain, copies should be available to each major design unit. The advertising sections of electrical magazines contain excellent material, usually well-illustrated and presented in a clear and readable form, concerning the construction and application of equipment. Such literature may be promotional; it may present the advertiser's equipment or methods in a best light and should be carefully evaluated. Manufacturers' catalogs are a valuable source of equipment information. Some of the larger manufacturers' complete catalogs are very extensive, covering dozens of volumes; however, these companies may issue abbreviated or condensed catalogs that are adequate for most applications. Data sheets referring to specific items are almost always available from the sales offices. Some technical files may be kept on microfilm at larger design offices for use either by projection or by printing. Manufacturers' representatives, both sales and technical, can do much to provide complete information on a product.

Chapter 2

Description of a short-circuit current

2.1 Introduction

Electric power systems are designed to be as fault-free as possible through careful system and equipment design, proper equipment installation and periodic equipment maintenance. However, even when these practices are used, faults do occur. Some of the causes of faults are as follows:

- a) Presence of animals in equipment
- b) Loose connections causing equipment overheating
- c) Voltage surges
- d) Deterioration of insulation due to age
- e) Voltage or mechanical stresses applied to the equipment
- f) Accumulation of moisture and contaminants
- g) The intrusion of metallic or conducting objects into the equipment such as grounding clamps, fish tape, tools, jackhammers or pay-loaders
- h) A large assortment of "undetermined causes"

When a short-circuit occurs in a electric power distribution system, several things can happen, such as the following:

- 1) The short-circuit currents may be very high, introducing a significant amount of energy into the fault.
- 2) At the fault location, arcing and burning can occur damaging adjacent equipment and also possibly resulting in an arc-flash burn hazard to personnel working on the equipment.
- 3) Short-circuit current may flow from the various rotating machines in the electrical distribution system to the fault location.
- 4) All components carrying the short-circuit currents will be subjected to thermal and mechanical stresses due to current flow. This stress varies as a function of the magnitude of the current squared and the duration of the current flow (I^2t) and may damage these components.
- 5) System voltage levels drop in proportion to the magnitude of the short-circuit currents flowing through the system elements. Maximum voltage drop occurs at the fault location (down to zero for a bolted fault), but all parts of the power system will be subject to a voltage drop to some degree.

2.2 Available short-circuit current

The "available" short-circuit current is defined as the maximum possible value of short-circuit current that may occur at a particular location in the distribution system assuming that no fault related influences, such as fault arc impedances, are acting to reduce the fault current. The available short-circuit current is directly related to the size and capacity of the

power sources (utility, generators, and motors) supplying the system and is typically independent of the load current of the circuit. The larger the capacity of the power sources supplying the system, the greater the available short-circuit current (generally). The main factors determining the magnitude and duration of the short-circuit currents are the type of fault, fault current sources present, and the impedances between the sources and the point of the short circuit. The characteristics, locations, and sizes of the fault current sources connected to the distribution system at the time the short circuit occurs have an influence on both the initial magnitude and the wave shape of the fault current.

Alternating current synchronous and induction motors, generators, and utility ties are the predominant sources of short-circuit currents. At the time of the short-circuit, synchronous and induction motors will act as generators and will supply current to the short-circuit based upon the amount of stored electrical energy in them. In an industrial plant, motors often contribute a significant share of the total available short-circuit current.

2.3 Symmetrical and asymmetrical currents

The terms “symmetrical” current and “asymmetrical” current describe the shape of the ac current waveforms about the zero axis. If the envelopes of the positive and negative peaks of the current waveform are symmetrical around the zero axis, they are called “symmetrical current” envelopes (Figure 2-1). The envelope is a line drawn through the peaks or crests of the waves.

If the envelopes of positive and negative peaks are not symmetrical around the zero axis, they are called “asymmetrical current” envelopes. Figure 2-2 shows a fully offset (non-decaying) fault current waveform. The amount of offset that will occur in a fault current waveform depends on the time at which the fault occurs on the ac voltage waveform and the network resistances and reactances. The current in a purely reactive network could have any offset from none to fully offset, depending on the time of its inception, and the offset would be sustained (not decaying). A fault occurring in a purely resistive system would have no offset in the current waveform. A network containing both resistances and reactances will generally begin with some offset in the current (up to full) and gradually the current will become symmetrical (because of the decay of the offset) around the zero axis.

As stated previously, induction and synchronous machines connected on the system supply current to the fault and, because of the limited amount of stored electrical energy in them, their currents decay with time. Figure 2-3 shows the symmetrical portion of a decaying fault current waveform typical for such equipment.

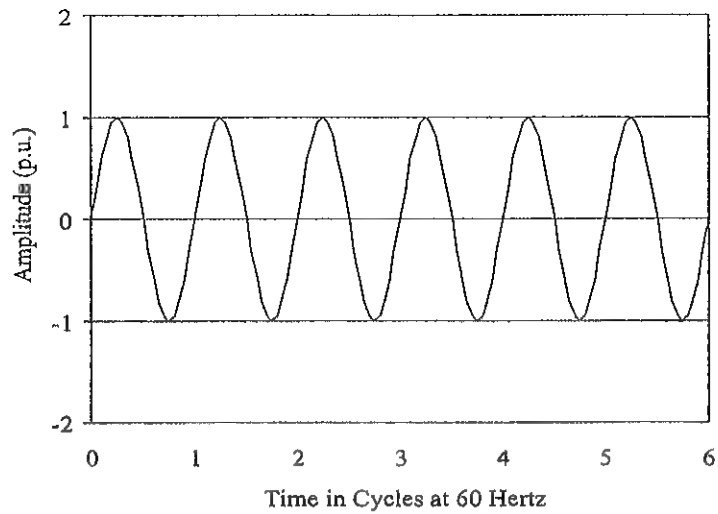


Figure 2-1—Symmetrical ac wave

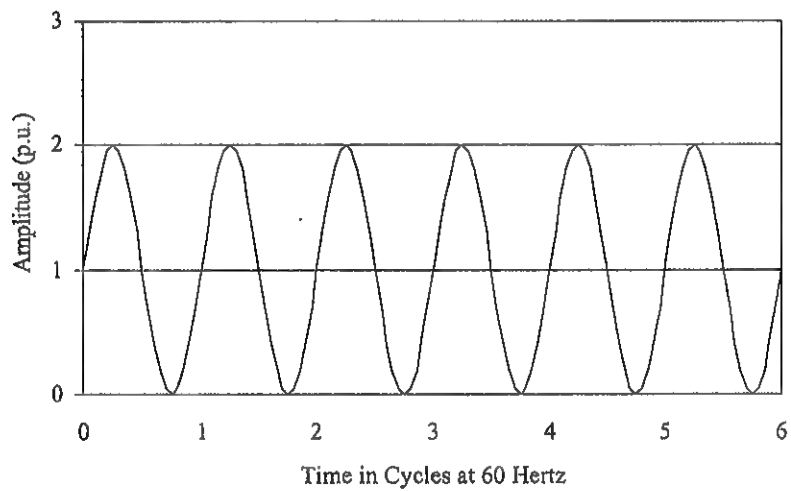


Figure 2-2—Totally offset ac wave

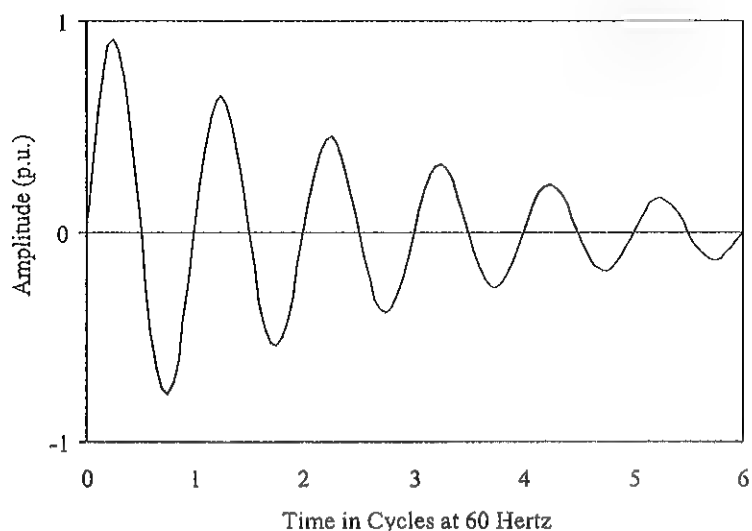


Figure 2-3—Decaying symmetrical ac wave

Short-circuit currents are nearly always asymmetrical during the first few cycles after the short circuit occurs and contain both dc and ac components. The dc component is shown in Figure 2-4. The asymmetrical current component (dc) is always at a maximum during the first cycle after the short circuit occurs. This dc component gradually decays to zero. A typical asymmetrical short-circuit current waveform is shown in Figure 2-5.

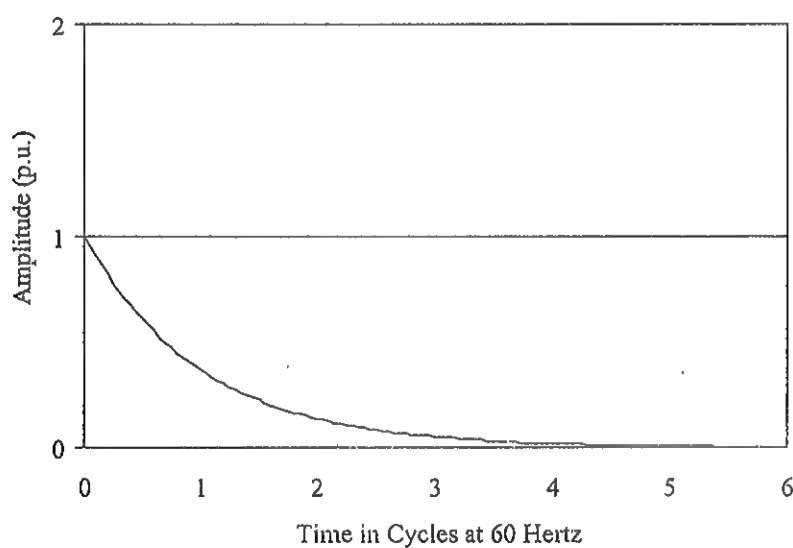


Figure 2-4—Decaying dc wave

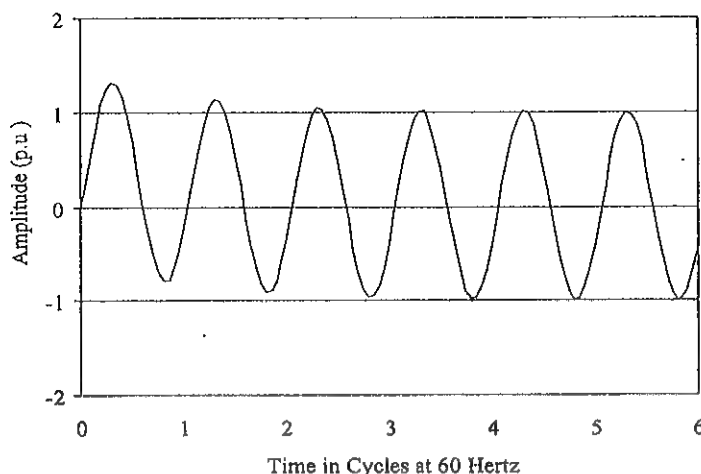


Figure 2-5—Asymmetrical fault current ac wave

2.4 Short-circuit calculations

The calculation of the precise magnitude of a short-circuit current at a given time after the inception of a fault is a rather complex computation. Consequently, simplified methods have been developed that yield conservative calculated short-circuit currents that may be compared with the assigned (tested) fault current ratings of various system overcurrent protective devices. Figure 2-6 provides a means of understanding the shape of the fault current waveform, and consequently the fault current magnitude at any point in time. The circuit consists of an ideal sinusoidal voltage source and a series combination of a resistance, an inductance, and a switch. The fault is initiated by the closing of the switch. The value of the rms symmetrical short-circuit current I , is determined through the use of the proper impedance in Equation (2.1):

$$I = \frac{E}{Z} \quad (2.1)$$

where

E is the rms driving voltage

Z (or X) is the Thevenin equivalent system impedance (or reactance) from the fault point back to and including the source or sources of short-circuit currents for the distribution system

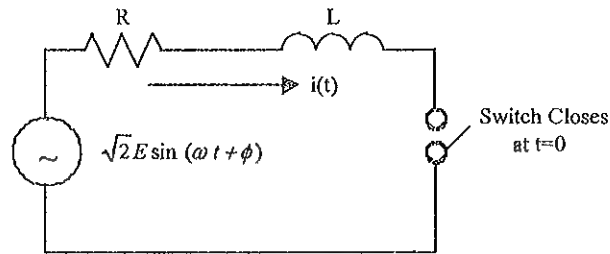


Figure 2-6—Circuit model for asymmetry

One simplification that is made is that all machine internal voltages are the same. In reality, the equivalent driving voltages used are the internal voltages of the electrical machines where each machine has a different voltage based on loading and impedance. During a fault, the machine's magnetic energy or its internal voltage is reduced faster than it can be replaced by energy supplied by the machine's field. This results in a decay (gradual reduction) of driving voltage over time. The rate of decay differs for each source. The resistance and reactance of machines is a fixed value based on the physical design of the equipment. Solving a multi-element system with many varying voltage sources becomes cumbersome. The same current can be determined by holding the voltage fixed and varying the machine impedance with time. This interchange helps to simplify the mathematics. The value of the impedance that must be used in these calculations is determined with regard to the basis of rating for the protective device or equipment under consideration. Different types of protective devices or equipment require different machine impedances to determine the fault current duty. Equipment evaluated on a first cycle criteria would use a lower machine impedance and hence a higher current than equipment evaluated on an interrupting time basis (1.5–8 cycles), which uses a higher impedance.

The determination of how the fault current behaves as a function of time involves expansion of Equation (2.1) and the solution of the following differential equation [Equation (2.2)] for current i :

$$Ri + L \frac{di}{dt} = \sqrt{2} E \sin(\omega t + \phi) \quad (2.2)$$

where

- E is the rms magnitude of the sinusoidal voltage source
- i is the instantaneous current in the circuit at any time after the switch is closed
- R is the circuit resistance in ohms
- L is the circuit inductance in Henries (= circuit reactance divided by ω)
- t is time in seconds
- ϕ is the angle of the applied voltage in radians when the fault occurs
- ω is the $2\pi f$ where f is the system frequency in hertz (Hz)

The details of the solution of Equation (2.2) are well covered in the references listed at the end of this chapter and in electric power textbooks, so only the solution of the equation

will be stated here. Assuming the pre-fault current through the circuit to be zero (i.e., load current = 0), then the instantaneous current solution to Equation (2.2) is

$$i = -\frac{\sqrt{2}E}{Z}\sin(\alpha - \phi)e^{-\frac{\omega t R}{X}} + \frac{\sqrt{2}E}{Z}\sin(\omega t + \alpha - \phi) \quad (2.3)$$

$$i = -i_{dc}\sin(\alpha - \phi)e^{-\frac{\omega R t}{X}} + \sqrt{2} I_{ac, rms} \sin(\omega t + \alpha - \phi) \quad (2.4)$$

where

$$\phi = \tan^{-1}\left(\frac{\omega L}{R}\right) = \tan^{-1}\left(\frac{X}{R}\right)$$

$$X = \omega L$$

$$Z = \sqrt{R^2 + X^2}$$

if time t is expressed in cycles, Equation (2.4) becomes

$$i = -i_{dc}\sin(\alpha - \phi)e^{-\frac{2\pi R t}{X}} + \sqrt{2} I_{ac, rms} \sin(2\pi t + \alpha - \phi) \quad (2.5)$$

The first term in Equation (2.3) represents the transient dc component of the solution. The initial magnitude $\sqrt{2} E/Z \times \sin(\alpha - \phi)$ decays in accordance with the exponential expression. This dc component eventually disappears. The second term represents the steady-state ac component of the solution. The second term is a sinusoidal function of time whose crest value is simply the maximum peak value of the supply voltage divided by the magnitude of the Thevenin equivalent system impedance ($\sqrt{2} E/Z$) as viewed from the fault. The difference between the initial fault current magnitude and the final steady-state fault current magnitude depends only on the X/R ratio of the circuit impedance and the phase angle α of the supply voltage when the fault occurs. Note that at time zero the dc component of fault current is exactly equal in magnitude to the value of the ac fault current component but opposite in sign. This condition must exist due to the fact that the initial current in the circuit is zero and the fact that current cannot change instantaneously in the inductive circuit of Figure 2-6.

The significance of the transient and steady-state components of the fault current is best illustrated by considering an actual example. Figure 2-5 shows the response of a specific circuit with an X/R ratio of 7.5. The circuit is supplied by a 60 Hz source ($\omega = 377$), with the fault occurring (switch closes) when the voltage is at $\alpha = 58$ degrees. The plot of the current is obtained from the general solution of Equation (2.3).

2.5 Total short-circuit current

The total short-circuit current available in a distribution system is usually supplied from a number of sources, which can be grouped into three main categories. The first is the utility transmission system supplying the facility, which acts like a large, remote generator. The second includes “local” generators either in the plant or nearby in the utility. The third source category is synchronous and induction motors, which are located in many plants and facilities. All these are rotating machines; those of the second and third categories have machine currents that decay significantly with time due to reduction of flux in the machine during a short circuit. For a short circuit at its terminals, the induction motor symmetrical current disappears entirely after one to ten cycles while the current of a synchronous motor is maintained at a lower initial value by its energized field. Networks having a greater proportion of induction motors to synchronous motors will have quicker decays of ac short-circuit current components. The fault current magnitude during the first few cycles is further increased by the dc fault current component (Figure 2-4). This component also decays with time, increasing the difference in short-circuit current magnitude between the first cycle after the short circuit occurs and a few cycles later.

The total short-circuit current that has steady-state ac, decaying ac, and decaying dc current components can be expressed as shown in Equation (2.6). Figure 2-7 shows the circuit diagram and Figure 2-8 shows the response curve corresponding to Equation (2.6). Note that ac decaying sources cannot be specifically included in the equivalent circuit, but are assumed to be present.

$$i = i_{dc\ decay} + i_{ac\ steady\ state} + i_{ac\ decay} \quad (2.6)$$

With

$$i_{dc\ decay} = (I_{ac\ steady\ state}) \sin(\alpha - \phi) e^{-\frac{R\omega t}{X}}$$

$$i_{ac\ steady\ state} = \sqrt{2} I_s \sin(\omega t + \alpha - \phi)$$

$$i_{ac\ decay} = \sqrt{2} I_{ds} \sin(\omega t + \alpha - \phi) e^{-kt}$$

where

- I_s is the symmetrical steady-state rms current magnitude
- I_{ds} is the decaying symmetrical rms current magnitude
- k is a variable depending upon the mix and size of rotational loads
- t is in seconds

The magnitude and duration of the asymmetrical current depends upon the following two parameters:

- a) The X/R ratio of the faulted circuit
- b) The phase angle of the voltage waveform at the time the short circuit occurs

The greater the fault point X/R ratio, the longer will be the asymmetrical fault current decay time. For a specific X/R ratio, the angle of the applied voltage at the time of short-circuit initiation determines the degree of fault current asymmetry that will exist for that X/R ratio.

In a purely inductive circuit, the maximum dc current component is produced when the short circuit is initiated at the instant the applied voltage is zero ($\alpha = 0^\circ$ or 180° when using sine functions). The current will then be fully offset in either the positive or negative direction. Maximum asymmetry for any circuit X/R ratio often occurs when the short-circuit is initiated near voltage zero. The initial dc fault current component is independent of whether the ac component remains constant or decays from its initial value.

For any circuit X/R ratio, the voltage and current waveforms will be out of phase from each other by an angle corresponding to the amount of reactance in the circuit compared to the amount of resistance in the circuit. This angle is equal to $\tan^{-1}(2\pi f \times L/R)$. For a purely inductive circuit, the current waveform will be displaced from the voltage waveform by 90° (lagging). As resistance is added to the circuit this angular displacement will decrease to zero. In a purely resistive circuit, the voltage and current will be completely in-phase and without an offset.

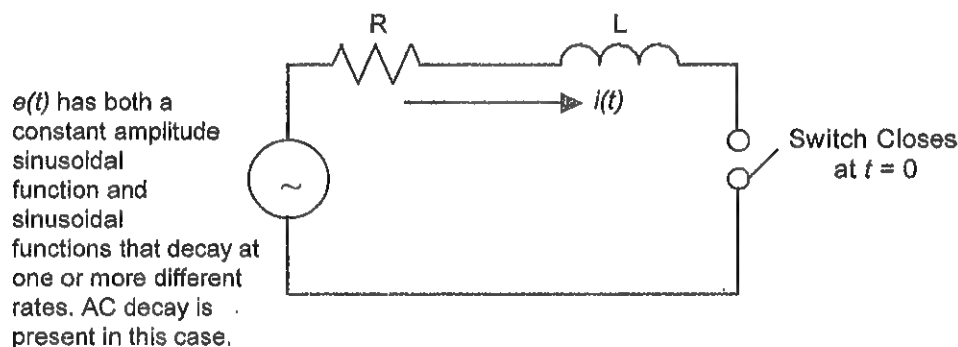


Figure 2-7—Circuit model with steady-state and decaying ac current sources

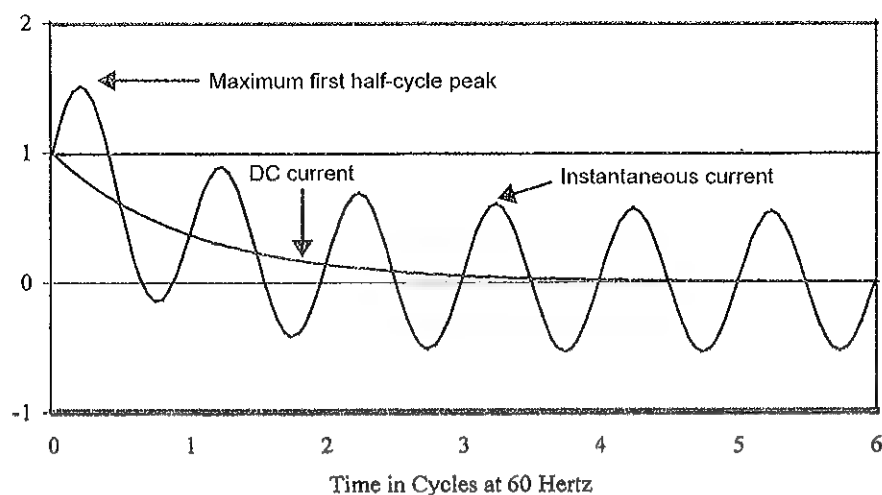


Figure 2-8—Asymmetrical ac short-circuit current made up of dc, decaying ac, and symmetrical ac current

2.6 Why short-circuit currents are asymmetrical

If a short-circuit occurs at the peak of the voltage waveform in a circuit containing only reactance, the short-circuit current will start at zero and trace a sine wave that will be symmetrical about the zero axis (Figure 2-1). If a short-circuit occurs at a voltage zero, the current will start at zero but cannot follow a sine wave symmetrically about the zero axis because in an inductive circuit the current must lag the applied voltage by 90° . This can happen only if the current is displaced from the zero axis as shown in Figure 2-2. The two cases shown in Figure 2-1 and Figure 2-2 represent the extremes. One represents a totally symmetrical fault current; the other represents a completely asymmetrical current. If the fault occurs at any point between a voltage zero and a voltage crest, the current will be asymmetrical to some degree depending upon the point at which the short-circuit occurs on the applied voltage waveform. In a circuit containing both resistance and reactance, the degree of asymmetry can vary between zero and the same fully offset limits as a circuit containing only reactance. However, the point on the applied voltage waveform at which the short-circuit must occur to produce maximum fault current asymmetry depends upon the ratio of circuit reactance to circuit resistance.

2.7 DC component of short-circuit currents

Short-circuit currents are analyzed in terms of two components—a symmetrical current component and the total current that includes a dc component as shown in Figure 2-1 and Figure 2-4, respectively. As previously discussed, the asymmetrical fault current component is at a maximum during the first cycle of the short circuit and decays to a steady-state value due to the corresponding changes of the magnetic flux fields in the machine. In all practical circuits containing resistance and reactance, the dc component will also decay to

zero as the energy represented by the dc component is dissipated as I^2R heating losses in the circuit. The rate of decay of the dc component is a function of the resistance and reactance of the circuit. In practical circuits, the dc component decays to zero in one to 30 cycles.

2.8 Significance of current asymmetry

Current asymmetry is significant for two important reasons. First is the electromagnetic force exerted on equipment parts carrying the current and second is the thermal energy content of the fault current. The peak characteristics of both the magnetic forces and the thermal heating are a function of the square of the current, i^2 . In Figure 2-8, the first peak of the asymmetrical fault current waveform has a magnitude that is approximately 1.5 times the crest value of the steady-state waveform. At the first current peak, the magnetic forces exerted on current carrying equipment by the asymmetrical fault current are about 2.25 times the peak forces that would be caused by symmetrical fault current during the first cycle. In addition, these large values do not immediately vanish. Consequently, the i^2t (thermal or heating effect) content of the current is also much greater. Magnetic forces and heating affect the design and application of the protective equipment used on a power system.

This is where the significance of current asymmetry lies. In designing and applying devices that will be exposed to fault currents, the transient (asymmetrical) as well as the steady-state fault currents magnitudes must be considered, because both the mechanical forces and the thermal effects placed on protective equipment can be greatly magnified in the initial fault current period.

2.9 The application of current asymmetry information

In the previous discussion, a single phase current was examined to give an understanding of asymmetry. In a three-phase system with a bolted three-phase fault, the sum of the current at any point in time in the three phases must add to zero. Therefore, if one phase has a maximum offset, then the other two phases must have a negative offset to balance current. The decay time constant of all phases is the same.

The maximum magnetic force produced on a circuit element, such as a breaker, occurs at the instant the fault current through the circuit element is at a maximum. From an equipment design and application viewpoint, the phase with the largest of the fault current peaks is of particular interest. This current value subjects the equipment to the most severe magnetic forces. The largest fault current peak typically occurs in the first current cycle when the initiation of the short-circuit current is near or coincident with the applied voltage passing through zero. This condition is called the condition of maximum asymmetry.

In the application of equipment that can carry fault current such as circuit breakers, switches, transformers, and fuses, the total available short-circuit current must be determined. For correct equipment application, knowledge of the minimum test X/R ratio or maximum power factor of the applied fault current used in the acceptance test by ANSI, NEMA, or UL is also required. Peak fault current magnitudes are significant for some

devices, such as low-voltage breakers, while asymmetrical rms current magnitudes are equally significant for high-voltage circuit breakers. This leads to the need to develop an X/R ratio dependent short-circuit calculation for proper comparison to the equipment being applied. The fault current calculation needs to take into account the ac component and the transient dc component of the calculated fault current to determine the total maximum peak or rms current magnitude that can occur in a circuit. When the calculated fault X/R ratio is greater than the equipment test X/R ratio, the higher total fault current associated with the higher X/R ratio must be taken into account when evaluating the application of the equipment. The application of equipment is detailed in Chapter 10.

The bibliography at the end of this chapter provides a thorough treatment of the mathematics involved in analyzing the maximum current under the conditions of asymmetry. While this chapter provides a summary, the details of this analysis are worthwhile for a clear understanding of the implications of asymmetry. In this summary, it has been shown that the effects of asymmetry are dependent only upon the fault point X/R ratio of the circuit and the instant of fault initiation.

The references show that the effects of the peak fault current magnitude and the energy content of the first current cycle are much greater than the effect of the rms value. For the condition of maximum asymmetry, the rms value of the first cycle fault current theoretically can be as great as 1.732 times the steady-state rms symmetrical fault current component. However, the peak first cycle current for the same condition can be up to two times the peak of the steady-state current component, and the magnetic forces can be four times that of the rms symmetrical ac component. From the equipment design viewpoint, these peak currents and energy comparisons are the maximum that the equipment must withstand. For ANSI rated equipment, the maximum asymmetrical rms current provides this measure of maximum capability.

It is important to know the terms defining the characteristic short-circuit current waveforms. The test short-circuit currents used for circuit breaker and fuse interrupting ratings have different test procedures and power factor (X/R ratios) requirements. For example, high-voltage power circuit breakers use rms current interrupting tests at a power factor of 6.7% ($X/R = 15$), while low-voltage circuit breakers use peak currents at a power factor of 15% ($X/R = 6.59$). Molded case and insulated case circuit breakers have different (from 6.7% and 15%) test power factors that must be considered. If the calculated fault point X/R ratio is greater than the test X/R ratio of the interrupting device, then the calculation of equipment duty current is affected. The duty current correction is covered in Chapter 10.

2.10 Maximum peak current

After a bolted three-phase fault is initiated, the maximum peak current occurs in one phase during the first half-cycle, and is often assumed, usually erroneously, to occur when the symmetrical ac current component is at its peak. The familiar first half-cycle current assumption suggests that the highest first cycle peak current also occurs at one half-cycle in the phase that has the maximum initial dc component. This is also erroneous, except for faults that occur on purely inductive circuits, where the resistance is zero. For circuits with resistance, the absolute maximum fault current peak occurs before the symmetrical current

peak and before one-half cycle as shown on Figure 2-9. Figure 2-9 is drawn for fault in a circuit with a relatively low X/R ratio of 2 to emphasize these important characteristics. This analysis assumes fundamental 60 Hz voltage, linear impedances, no ac decaying sources, and no pre-fault load currents. The largest of these fault current peaks can be found mathematically by differentiating the current expression in Equation (2.2) with respect to its two independent variables t and α . The other variables E , R , X , and ω are fixed for any given circuit. Differentiating the expression shows the largest fault current peak occurs for zero voltage angle α . In this situation, the largest peak occurs in the first current cycle, so the current waveform resembles that shown in Figure 2-9.

Important characteristics shown on Figure 2-9 are as follows:

- 1) The short circuit starts at zero voltage.
- 2) The initial asymmetrical current is zero, due to the assumption of no pre-fault load current and item 3) below.
- 3) At the instant of fault initiation, the dc fault current value is equal in magnitude of the ac fault current value but opposite in sign.
- 4) The maximum fault current peak occurs before the first positive symmetrical fault current peak.

The maximum peak current is obtained by manipulation of partial derivatives of Equation (2.2) using an iterative approach and results in maximum peak and maximum rms currents multipliers as shown in Table 2-1 and Table 2-2. The values listed under the column headed "exact" have been calculated from these partial derivatives and are theoretically exact.

For circuit X/R ratios between 0.5 and 1000, the second column in Table 2-1 and Table 2-2 shows the time in cycles at which the maximum peak and maximum rms currents occur. Note that the rms value of a function is based on an average, over one period, of the function squared. Strictly speaking, a non-periodic function does not have an rms value, because no period exists over which to determine an average. When the function consists of a sinusoidal component and an exponentially-decaying dc term as is commonly found in power systems, it is common practice use the dc value at the half-cycle point in calculations of the total rms current. It should be noted that this half-cycle value does not necessarily correspond to the peak value of the total asymmetrical current. The use of the dc value evaluated at half-cycle is, however, very widely accepted and is the basis for numerous standards relating to short circuits and protective equipment.

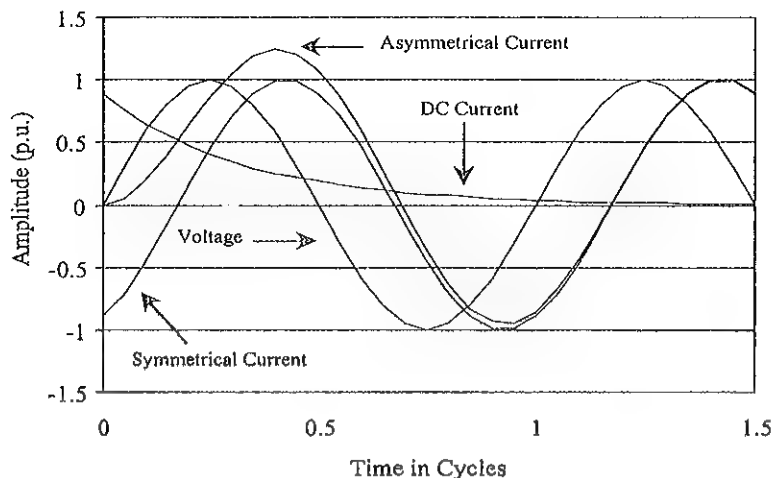


Figure 2-9—Maximum peak asymmetrical short-circuit current

Because the current is lagging the applied voltage by the angle of $\tan^{-1}(X/R)$, the peak current occurs before one half cycle. Only in a pure reactance circuit (X/R equals infinity) does the peak occur at the one half-cycle. Figure 2-9 illustrates a typical circuit where the peak occurs before the first half-cycle. The figure represents a circuit having a fault point X/R equal to 2.0 with the peak current occurring at approximately 0.40 cycles and a magnitude equal to 1.242 times the ac symmetrical peak current.

Calculating the peak current at a time of one half-cycle on a 60 Hz base by Equation (2.7) yields a non-conservative (lower than EXACT) value for the peak current. The peak current multipliers for the one half-cycle calculations are given in Table 2-1 and Table 2-2 under the columns labeled “half-cycle” and are shown to be less than the multipliers given under the column labeled “exact.” The “half-cycle” equation is shown in Equation (2.7):

$$I_{peak} = I_{ac\ peak} + I_{dc} = \sqrt{2}I_{ac, rms} + \left(1 + e^{-\frac{2\pi t}{X/R}}\right) \quad (2.7)$$

where $t = 0.5$ cycles

The IEC calculating procedure for short-circuit currents includes the following empirical formula [Equation (2.8)] for estimating the absolute maximum peak current value, knowing the circuit fault point X/R ratio. This expression provides a rather close approximation to the EXACT peak current values and is conservative for circuit fault point X/R ratios greater than three. Determining peak currents for circuit X/R ratio less than three is rarely necessary. Because most types of protective equipment short-circuit ratings are based on fault point X/R ratios greater than three (power factor lower than 31.6%), a current correction or multiplying factor is not needed. The peak current multipliers at one half cycle are given in Table 2-1 and Table 2-2 under the columns labeled “IEC.” The form of

Equation (2.7) should not be used for the peak current when applying equipment because it is non-conservative. The equation is given here for reference only. The “IEC” equation is shown in Equation (2.8):

$$I_{peak} = \sqrt{2} I_{ac, rms} \left(1.02 + 0.98 e^{-\frac{3}{X/R}} \right) \quad (2.8)$$

From the IEC Equation (2.8), the dc component would be as shown in Equation (2.9):

$$I_{dc} = \sqrt{2} I_{ac, rms} \left(0.02 + 0.98 e^{-\frac{3}{X/R}} \right) \quad (2.9)$$

An alternate equation is available that provides a closer approximation to the EXACT peak currents than either the “half cycle” or “IEC” methods. The expression has two parts. First, a fictitious time τ is calculated from Equation (2.10) and then substituted into Equation (2.7) for t . For convenience, Equation (2.7) is listed below Equation (2.10).

$$\tau = 0.49 - 0.1 e^{-\frac{X/R}{3}} \quad (2.10)$$

$$I_{peak} = I_{ac\ peak} + I_{dc} = \sqrt{2} I_{ac, rms} \left(1 + e^{-\frac{2\pi\tau}{X/R}} \right)$$

The peak current calculations provided by the combination of these two equations yields a very close approximation to the EXACT peak current and is conservative for most values of circuit X/R ratios greater than 0.81. The non-conservative errors for circuit X/R ratios around 10 are negligible. If a conservative multiplier is required for these circuit X/R ratios, then 0.0001 can be added to the peak current multiplier. The peak current multipliers for this alternate approach for the maximum half-cycle values are given in Table 2-1 under the columns labeled “violet approx.”

Equation (2.11), Equation (2.12), and Equation (2.13) are used for peak current factors in Table 2-1.

$$Half\ cycle_{peak} = I_{ac\ peak} \left(1 + e^{-\frac{\pi}{X/R}} \right) \quad (2.11)$$

$$IEC_{peak} = I_{ac\ peak} \left(1.02 + 0.98 e^{-\frac{3}{X/R}} \right) \quad (2.12)$$

$$Violet\ approx_{peak} = I_{ac\ peak} \left(1 + e^{-\frac{2\pi\tau}{(X/R)}} \right) \quad (2.13)$$

where

$$\tau = 0.49 - 0.1e^{-\frac{(X/R)}{3}}$$

Negative percent error occurs when the above equations predict a value less than the "EXACT" value for the first cycle peak current. Therefore, the equations can be considered as non-conservative for any conditions that produce negative error.

A similar set of equations can be used for first cycle rms current factors where

$$I_{rms} = \sqrt{I_{ac\ rms}^2 + I_{dc}^2} \quad (2.14)$$

Recall the difficulty in determining the rms value of a non-periodic waveform. Equation (2.14) is valid only when I_{dc} is constant. In short-circuit currents, the dc term is a decaying exponential and is not constant; it is a very common practice to evaluate this term at 1/2 cycle after fault initiation even though this point in time does not necessarily correspond to the maximum peak value of the asymmetrical fault current.

These equations are given as follows and used in Table 2-2.

$$IEC_{rms} = I_{ac\ rms} \sqrt{1 + 2 \left(1.02 + 0.98e^{-\frac{3}{(X/R)}} \right)^2} \quad (2.15)$$

$$Half\ cycle_{rms} = I_{ac\ rms} \sqrt{1 + 2 \left(e^{-\frac{\pi}{(X/R)}} \right)^2} \quad (2.16)$$

$$Violet\ approx_{rms} = I_{ac\ rms} \sqrt{1 + 2e^{-\frac{4\pi\tau}{(X/R)}}} \quad (2.17)$$

where

$$\tau = 0.49 - 0.1e^{-\frac{X/R}{3}}$$

As with the first cycle peak current, any of the above equations that produce negative percent errors can be considered non-conservative under the specified conditions.

Equation (2.16) has been given here for reference because it has been used in other texts. Use of this equation is not recommended in those instances where the first cycle rms current value obtained is to be used for equipment application because the current value obtained is non-conservative.

Table 2-1—Differences in per-unit peak currents based on Equation (2.11), Equation (2.12), and Equation (2.13) (one per-unit equals ac peak)

Exact				IEC		Half-cycle		Violet approx	
X/R	Time to peak (CY)	DC	Maximum peak	Maximum peak	Percent error	Maximum peak	Percent error	Maximum peak	Percent error
0.5	0.3213	0.0078	1.0078	1.0224	1.45	1.0019	-0.59	1.0061	-0.16
1.0	0.3635	0.0694	1.0694	1.0688	-0.06	1.0432	-2.45	1.0722	0.26
1.5	0.3891	0.1571	1.1571	1.1526	-0.39	1.1231	-2.94	1.1656	0.73
2.0	0.3977	0.2418	1.2418	1.2387	-0.25	1.2079	-2.73	1.2521	0.83
2.5	0.4063	0.3157	1.3157	1.3152	-0.04	1.2846	-2.36	1.3255	0.75
3.0	0.4282	0.3786	1.3786	1.3805	0.14	1.3509	-2.01	1.3870	0.61
3.5	0.4357	0.4319	1.4319	1.4359	0.28	1.4075	-1.70	1.4388	0.48
4.0	0.4417	0.4774	1.4774	1.4829	0.37	1.4559	-1.45	1.4827	0.36
6.0	0.4575	0.6057	1.6057	1.6144	0.54	1.5924	-0.83	1.6072	0.09
8.0	0.4665	0.6842	1.6842	1.6935	0.56	1.6752	-0.53	1.6843	0.01
10.0	0.4735	0.7368	1.7368	1.7460	0.53	1.7304	-0.37	1.7367	-0.01
14.0	0.4795	0.8027	1.8027	1.8110	0.46	1.7990	-0.20	1.8029	0.01
20.0	0.4852	0.8566	1.8566	1.8635	0.37	1.8546	-0.11	1.8574	0.04
25.0	0.4880	0.8832	1.8832	1.8892	0.32	1.8819	-0.07	1.8841	0.05
30.0	0.4899	0.9015	1.9015	1.9067	0.27	1.9006	-0.05	1.9025	0.05
40.0	0.4923	0.9250	1.9250	1.9292	0.22	1.9245	-0.03	1.9259	0.05
50.0	0.4938	0.9395	1.9395	1.9429	0.18	1.9391	-0.02	1.9403	0.04
75.0	0.4958	0.9591	1.9591	1.9616	0.12	1.9590	-0.01	1.9598	0.03
100.0	0.4969	0.9692	1.9692	1.9710	0.09	1.9691	-0.00	1.9697	0.03
250.0	0.4987	0.9875	1.9875	1.9883	0.04	1.9875	-0.00	1.9878	0.01
500.0	0.4994	0.9937	1.9937	1.9941	0.02	1.9937	-0.00	1.9939	0.01
1000.0	0.4997	0.9969	1.9969	1.9971	0.01	1.9969	-0.00	1.9969	0.00

Table 2-2—Per-unit rms currents at peak ac current based on Equation (2.15), Equation (2.16), and Equation (2.17) (one per-unit equals ac rms)

Exact				IEC		Half cycle		Violet approx	
X/R	Time to peak (CY)	DC	Maximum peak	Maximum peak	Percent error	Maximum peak	Percent error	Maximum peak	Percent error
0.5	0.3213	0.0110	1.0001	1.0005	0.04	1.0000	−0.01	1.0000	−0.00
1.0	0.3635	0.0981	1.0048	1.0047	−0.01	1.0019	−0.29	1.0052	0.04
1.5	0.3891	0.2222	1.0244	1.0230	−0.13	1.0151	−0.91	1.0270	0.26
2.0	0.3977	0.3419	1.0568	1.0554	−0.13	1.0423	−1.37	1.0616	0.45
2.5	0.4063	0.4464	1.0951	1.0948	−0.03	1.0780	−1.57	1.1009	0.53
3.0	0.4282	0.5354	1.1343	1.1356	0.11	1.1164	−1.58	1.1400	0.50
3.5	0.4357	0.6108	1.1718	1.1747	0.25	1.1542	−1.50	1.1769	0.43
4.0	0.4417	0.6751	1.2066	1.2110	0.36	1.1899	−1.38	1.2108	0.35
6.0	0.4575	0.8566	1.3167	1.3248	0.61	1.3045	−0.93	1.3181	0.10
8.0	0.4665	0.9676	1.3915	1.4007	0.66	1.3827	−0.63	1.3916	0.01
10.0	0.4735	1.0420	1.4442	1.4536	0.65	1.4377	−0.45	1.4441	−0.01
14.0	0.4795	1.1352	1.5128	1.5216	0.58	1.5089	−0.26	1.5131	0.02
20.0	0.4852	1.2114	1.5709	1.5784	0.48	1.5687	−0.14	1.5717	0.05
25.0	0.4880	1.2491	1.6001	1.6066	0.41	1.5986	−0.09	1.6011	0.06
30.0	0.4899	1.2750	1.6203	1.6261	0.36	1.6193	−0.07	1.6214	0.06
40.0	0.4923	1.3082	1.6466	1.6513	0.28	1.6460	−0.04	1.6476	0.06
50.0	0.4938	1.3286	1.6629	1.6668	0.24	1.6625	−0.02	1.6638	0.06
75.0	0.4958	1.3564	1.6852	1.6880	0.16	1.6850	−0.01	1.6859	0.04
100.0	0.4969	1.3706	1.6966	1.6988	0.13	1.6965	−0.01	1.6972	0.03
250.0	0.4987	1.3966	1.7177	1.7186	0.05	1.7177	−0.00	1.7179	0.02
500.0	0.4994	1.4054	1.7248	1.7253	0.03	1.7248	−0.00	1.7250	0.01
1000.0	0.4997	1.4099	1.7285	1.7287	0.01	1.7284	−0.00	1.7285	0.00

2.11 Types of faults

In a three-phase power system, the type of faults that can occur are classified by the combination of conductors or buses that are faulted together. In addition, faults may be classified as either bolted faults or faults that occur through some impedance such as an arc. Each of the basic types of faults will be described and shown in Figure 2-10, but it should be noted that in a majority of cases, the fault current calculation required for the selection of interrupting and withstand current capabilities of equipment is the three-phase bolted fault with zero impedance.

A three-phase bolted fault describes the condition where the three conductors are physically held together with zero impedance between them, just as if they were bolted together. For a balanced symmetrical system, the fault current magnitude is balanced equally within the three phases. While this type of fault does not occur frequently, its results are used for protective device selection, because this fault type generally yields the maximum short-circuit current values. Figure 2-10(a) provides a graphical representation of a bolted three-phase fault.

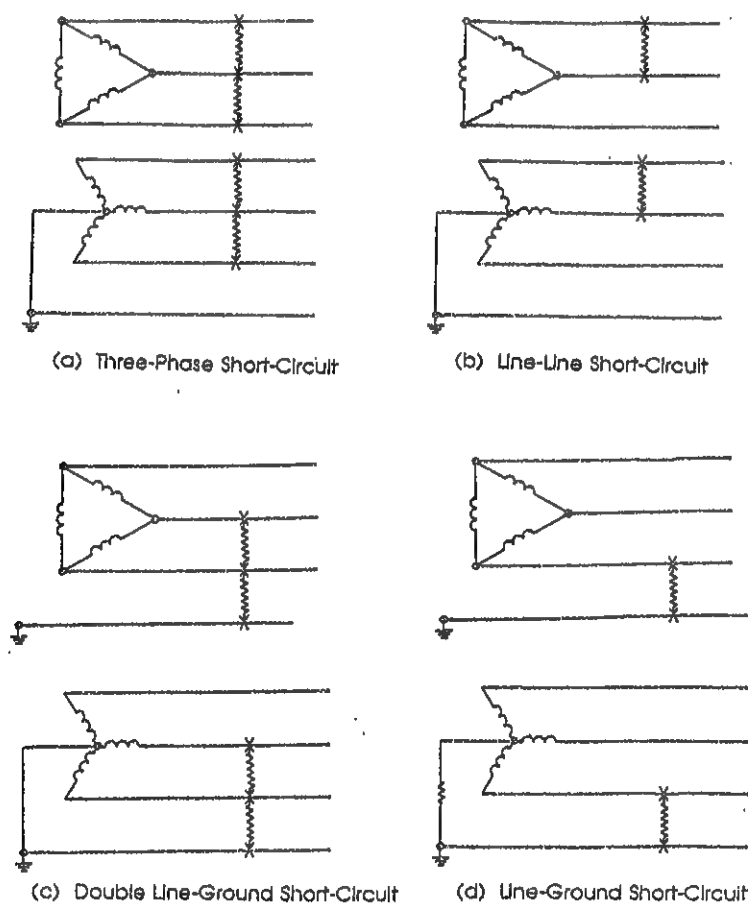


Figure 2-10—Designation of short-circuit categories

Bolted line-to-line faults, Figure 2-10(b), are more common than three-phase faults and have fault currents that are approximately 87% of the three-phase bolted fault current. This type of fault is not balanced within the three phases and its fault current is seldom calculated for equipment ratings because it does not provide the maximum fault current magnitude. The line-to-line current can be calculated by multiplying the three-phase value by 0.866, when the impedance $Z_1 = Z_2$. Special symmetrical component calculating techniques are not required for this condition.

Line-to-line-to-ground faults, Figure 2-10(c), are typically line-to-ground faults that have escalated to include a second phase conductor. This is an unbalanced fault. The magnitudes of double line-to-ground fault currents are usually greater than those of line-to-line faults, but are less than those of three-phase faults. Calculation of double line-to-ground fault currents requires the use of symmetrical components analysis. The impedance of the ground return path will affect the result, and should be obtained if possible.

Line-to-ground faults, Figure 2-10(d), are the most common type of faults and are usually the least disturbing to the system. The current in the faulted phase can range from near zero to a value slightly greater than the bolted three-phase fault current. The line-to-ground fault current magnitude is determined by the method in which the system is grounded and the impedance of the ground return path of the fault current. Calculation of the exact line-to-ground fault current magnitudes requires the special calculating techniques of symmetrical components. However, close approximations can be made knowing the method of system grounding used. On ungrounded distribution systems, the line-to-ground fault currents are near zero. Line-to-ground fault current magnitudes in distribution systems with resistance grounded system neutrals can be estimated by dividing the system line-to-neutral system voltage by the total value of the system ground-to-neutral resistance. Line-to-ground fault current magnitudes in distribution systems with a solidly grounded system will be approximately equal to the three-phase fault current magnitudes. Determining line-to-ground fault currents on long cable runs or transmission lines will require detailed ground return path impedance data and detailed calculation techniques.

2.12 Arc resistance

Fault arc resistance is a highly variable quantity and changes non-linearly with the current during a cycle and on a cycle-by-cycle basis. The higher the current, the greater the ionized area, and the lower the resistance of the arc. The voltage across the arc, although not fixed, is more constant than the resistance. Arcing fault current magnitudes on low-voltage systems (< 500 V) are more affected by fault resistance than are higher-voltage systems, and the fault current can be considerably smaller in magnitude than the bolted fault current values, as shown in Table 2-3. On higher-voltage networks (> 500 V), the fault arc resistance (and therefore the arc voltage) often is very low and approaches zero (bolted fault). Arcing faults in higher-voltage systems have been shown to have a ground fault current ranging from 0% to 100% of the bolted-fault current depending on the system voltage and the type of fault involved. The higher the possible fault current magnitude, the lower the fault resistance will be.

Table 2-3—Approximate minimum value of arcing fault current in per-unit of three-phase bolted fault

Type of arcing fault	System voltage	
	480Y/277V	208Y/120V
Three-phase	89%	12%
Line-to-line	74%	2%
Line-to-ground	38%	1%

The environment in which the fault takes place has an effect on the fault resistance and its continuity. An arcing fault in a confined area is easily perpetuated due to the concentration of ionized gases allowing easy current flow. An arc occurring on open conductors is elongated due to heat convection, thereby allowing cooling of ionized gas and the arc may extinguish itself.

Arcing fault currents are known to be very erratic in nature and do not provide a constant resistance during any one cycle. Over several cycles, the arc ignites due to uncooled ionized gases, almost extinguishes, then fully ignites again with varying current. There is not an exact equation available to determine arcing fault resistance. However, the reference works of Alm, Brown, and Strom [B1]¹ provide an approximation [Equation (2.18), Equation (2.19), and Equation (2.20)].

$$\frac{V}{\text{cm}} = 50 \left(\frac{P}{I^2} \right)^{1/6} \quad (2.18)$$

or in terms of resistance

$$\frac{R}{\text{cm}} = 50(P)^{1/6}(I)^{3/4} \quad (2.19)$$

where

V = voltage, volts

cm = arc length, centimeters

P = pressure in atmosphere (1 atm = 14.696 PSIA)

I = current in kiloamperes

R = resistance in ohms

Note that the equation parameters contain currents that make the application of Ohm's law non-linear and more complex. It should also be noted that the equations provide voltage

¹The numbers in brackets correspond to those of the bibliography in 2.13.

and resistance per centimeter. Therefore, the total arc voltage or resistance can be determined by multiplying Equation (2.18) and Equation (2.19) by the total arc length.

The instantaneous arc resistance at current peak can be calculated using Equation (2.20).

$$R = 11.6 \times l \times \frac{1.1}{I_x} \quad (2.20)$$

where

l = length of arc in centimeters
 I_x = peak current in kiloamperes

In the calculation of fault current magnitudes, maximum ampere conditions for equipment evaluation is often the concern and arcing fault impedance or arc resistance is considered zero.

2.13 Bibliography

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Chapter 3

Calculating techniques

3.1 Introduction

In order to calculate, with a reasonable degree of accuracy, the short-circuit current that can be expected to flow in a system, it is necessary to find an equivalent circuit for each system element that will adequately represent its performance under short-circuit conditions. Without the use of simplifying techniques, one is often faced with the necessity of solving complex differential equations to determine the short-circuit current.

In this chapter, various calculating techniques will be discussed with particular emphasis placed on simplifying techniques and manipulations that will provide acceptable results using system conditions that are recognized and accepted.

3.2 Fundamental principles

A basic ac power circuit containing resistance (R), inductance (L), and capacitance (C) is shown in Figure 3-1. For completeness, the series capacitor is shown, although its use in power circuits is limited. The general expression relating the instantaneous current response (i) and the instantaneous exciting source voltage (e) in such a circuit will take the form (see IEEE Std 141™-1993 [B6]):¹

$$e = L \frac{di}{dt} + Ri + \frac{1}{C} \int i dt + e_0 \quad (3.1)$$

$$e = L \frac{d^2 Q}{dt^2} + R \frac{dQ}{dt} + \frac{Q}{C} + e_0 \quad (3.2)$$

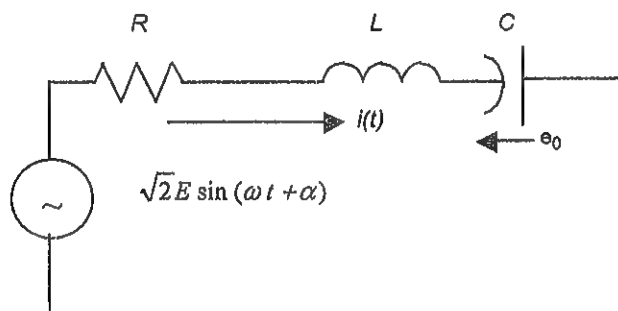


Figure 3-1—Series RLC circuit

¹The numbers in brackets correspond to those of the bibliography in 3.17.

The expression for the response (for current) involves the solution of a differential equation as shown in many electrical engineering textbooks. However, industrial and commercial power system networks contain many branches composed of series and parallel combinations of resistance, inductance and capacitance, which add greatly to the complexity of using the fundamental expression for circuit analysis. In addition, the calculation of system short-circuit currents is further complicated by the varying fluxes (driving voltages) in equipment along with the pre-fault and post-fault steady-state behavior. In calculating short-circuit currents, it is expedient to use techniques that will simplify the general circuit equation as much as possible while still providing valid results that are sufficiently accurate for their intended purpose.

Each of the network theorems and calculating techniques described in this chapter are valid for a specific calculation. They place various constraints on the general circuit equation in order to achieve calculation simplicity. It must be emphasized that these constraints must have some basis in order to obtain valid results. Fortunately, it is often possible to introduce appropriate corrections artificially when restraints are violated by system conditions. However, in certain cases it may be necessary to use the formal differential equations to obtain a valid solution.

The following constraints are common to all of the techniques that will be discussed, with the exception of the Fourier representation.

- 1) The ac source frequency must be constant. In power system short-circuit analysis, it is reasonable to assume constant system frequency for the fault duration except for very rare and special cases.
- 2) The impedance coefficients R , L , and C must be constant (saturated values). Again, for the majority of short-circuit calculations this restraint causes no difficulty since the maximum fault current is of concern and the fault resistance is taken to be zero when the equipment rating is evaluated. The following, however, are examples of system conditions where the restraint will be violated. When an arc becomes a series component of the circuit impedance, the R that it represents is not constant. For example, at a current of one ampere, it is likely to be 100 ohms, yet at a current of 1000 amperes it would very likely be about 0.1 ohms (see IEEE Std 141-1993 [B6]). During each half-cycle of current flow, the arc resistance would traverse this range. It is difficult to determine a proper resistance value to insert in the 60 Hz network. A correct value of R does not compensate for the violation of the constraint that demands that R be a constant. The variation in R lessens the impedance to high-magnitude current, which results in a wave shape of current that is more peaked than a sine wave. The current now contains harmonic terms. Because they result from a violation of analytical restraints, they will not appear in the calculated results. Their character and magnitude must be determined by other means and the result artificially introduced into the solution for fault current.

A similar type of non-linearity may be encountered in electromagnetic elements in which iron plays a part in setting the value of L . If the ferric parts are subject to large excursions of magnetic density, the value of L may be found to drop substantially when the flux density is driven into the saturation region. The effect

of this restraint violation will, like the case of variable R , result in the appearance of harmonic components in the true circuit current.

- 3) The driving voltage and its phase angle are assumed to be constant. In reality, however, the machine's internal driving voltage varies with machine loading and time. During a fault, the machine's magnetic energy or internal voltage is reduced faster than it can be replaced by energy supplied by the machine's field. The rate of decay differs for each source. In addition, the angles between machines begin to change as some accelerate and others slow down.

The resistance and reactance of machines are fixed values based on the physical design of the equipment. Solving a system with many varying driving voltage sources becomes cumbersome. The same current can be determined by holding the voltage constant and varying the machine impedance. This interchange helps to simplify the mathematics. The value of the impedance that must be used in these calculations depends on the basis of rating for the protective device or equipment under consideration. Different types of protective devices or equipment require different machine impedances to determine the fault current duty. Equipment evaluated on a first-cycle criteria would use a lower machine impedance and hence a higher current than equipment evaluated on an interrupting time basis.

- 4) The fault current source must be sinusoidal. Most voltages and currents used for transmission and utilization of electric power are generated by the uniform rotation of an armature in a magnetic field; the resulting steady-state voltage is periodic and has a waveform that is nearly a pure sine wave or one that can be resolved into a series of sine waves.

The vector impedance analysis recognizes only the steady-state sine wave electrical quantities and does not include the effects of abrupt switching. Fortunately, the effects of switching transients can be analyzed separately and added provided the network is linear. An independent solution can be obtained from a solution of the formal differential equations of the form of Equation (3.1) (see IEEE Std 141-1993 [B6]).

In the case of a totally resistive (R) network, (Figure 3-2), the closure of the switch SW causes the current to immediately assume the value that would exist in steady state. No transient will be produced.

In the case of inductance (L), (Figure 3-3), an understanding of the switching transient can be best acquired using the expression shown in Equation (3.3).

$$e = L \frac{di}{dt} \quad (3.3)$$

or expressed in terms of i .

$$\frac{di}{dt} = \frac{e}{L} \quad (3.4)$$

This expression tells us that the application of a driving voltage to an inductance will create a time-rate-of-change in the resultant current flow. The current waveform, one example of which is shown in Figure 3-3, may be fully offset or not offset at all, depending on the point on the applied voltage wave at which the switch is closed. The waveform in Figure 3-3 assumes a voltage angle (at switch closing) of 180 degrees, so a full negative offset will be produced.

At 1/2 cycle in Figure 3-3, the steady-state current curve waveform begins with a maximum negative dc offset. The offset is negative because the voltage at 1/2 cycle is “zero going negative,” meaning that the instantaneous value is zero at 1/2 cycle, but the next value will be negative. At this same instant (1/2 cycle), the 90 degree lagging current through the inductor will be at a positive peak. Because the switch has been open prior to this instant, the inductor current must be zero at the instant the switch closes. Because the steady-state inductor current will be at its positive peak value at 1/2 cycle, a constant current equal to the negative of this peak value must be produced starting at 1/2 cycle such that the sum of the steady-state waveform and the constant is zero at 1/2 cycle. In general, the transient that is produced when the switch is closed will take the form of a dc current component whose value may be anything between zero and the steady-state crest value (either positive or negative), depending on the angle of closing.

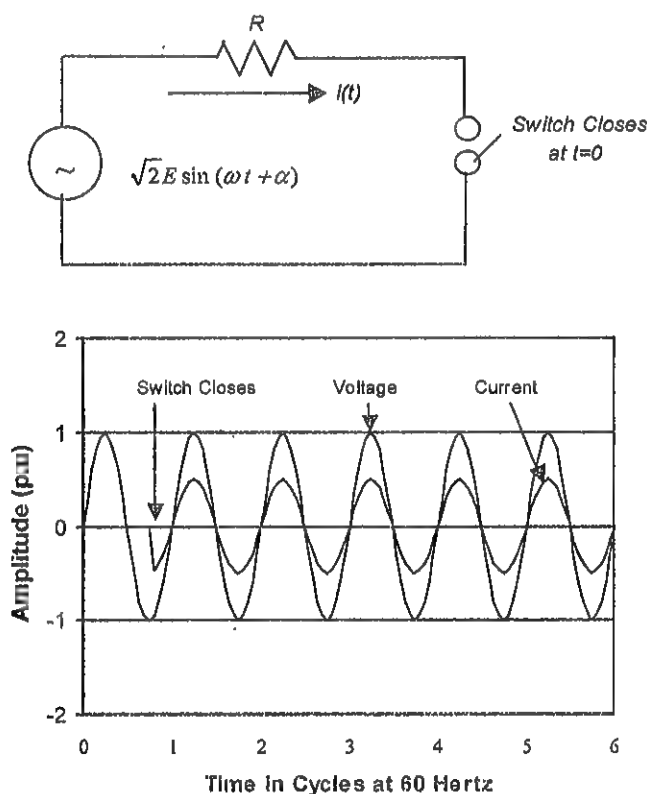


Figure 3-2—Switching a resistive circuit

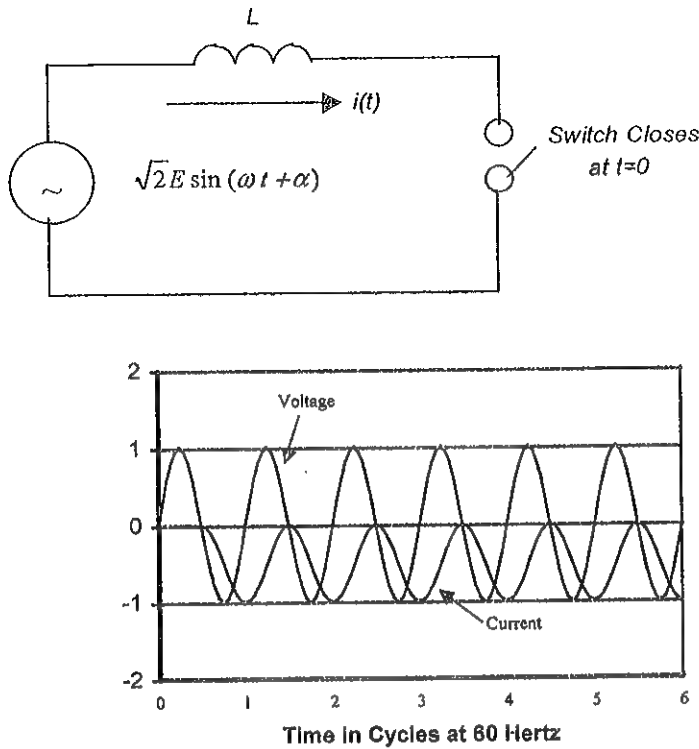


Figure 3-3—Switching an Inductive circuit

If the circuit contained no resistance, as depicted in Figure 3-3, the constant current would continue forever and the total waveform (the sum of this constant value and the sinusoidal steady-state current) would remain in the offset form. The presence of resistance causes the constant (often called dc) component to be dissipated exponentially. The complete expression for the current would take the form shown in Equation (3.5):

$$i = -\frac{\sqrt{2} E}{Z} \sin(\alpha - \phi) e^{-\frac{\omega t R}{X}} + \frac{\sqrt{2} E}{Z} \sin(\omega t + \alpha - \phi) \quad (3.5)$$

In Equation (3.5), the first part of the expression for the current has a constant term modified by a decaying exponential term (often called a decaying dc term). The second part of the equation is a steady-state sinusoidal term. To help distinguish these two terms, $\sqrt{2} E/Z$ will be identified as i_{dc} in the first term and $\sqrt{2} I_{ac,rms}$ in the second term. Note that at time $t = 0$ (the instant of fault initiation), these two terms are equal.

$$i = -i_{dc} \sin(\alpha - \phi) e^{-\frac{\omega t R}{X}} + \sqrt{2} I_{ac,rms} \sin(\omega t + \alpha - \phi) \quad (3.6)$$

where

$$\begin{aligned}\phi &= \tan^{-1}(\omega L/R) = \tan^{-1}(X/R) \\ X &= \omega L \\ Z &= (R^2 + X^2)^{1/2}\end{aligned}$$

If time t is expressed in cycles, Equation (3.6) becomes:

$$i = -i_{dc} \sin(\alpha - \phi) e^{-\frac{2\pi R}{X} t} + \sqrt{2} I_{ac,rms} \sin(2\pi t + \alpha - \phi) \quad (3.7)$$

The presence of dc current components may introduce unique problems in providing selectivity in relay coordination between some types of overcurrent devices. It is particularly important to keep in mind that these transitory dc currents are not disclosed by the steady-state circuit solution often used in short-circuit fault calculations, but must be introduced artificially by the analyst, or by established rules and guidelines. A detailed differential equation model of the entire network, including machines using a dynamic flux model, would be required to obtain the transient currents.

It is common practice that the analyst considers the switching transient to occur only once during one excursion of short-circuit current flow. An examination of representative oscillograms of short-circuit currents will often display repeated instances of momentary current interruptions. At times, an entire half-cycle of current will be missing. In other cases, especially in low-voltage circuits, there may be present a whole series of chops and jumps in the current pattern. A switching interrupter, especially when switching a capacitor circuit, may be observed to restrike two, or perhaps three times before complete interruption is achieved. The restrike generally occurs when the potential difference across the switching contacts is high. It is entirely possible that switching transients, both simple dc and ac transitory oscillations, may be created in the circuit current a number of times during a single incident of short-circuit current flow. The analyst must remain mindful of possible trouble.

3.3 Short-circuit calculation procedure

The procedure for calculating short-circuit currents in industrial and commercial power systems can be described in five basic steps. Each of these steps is covered in more detail in this and later chapters.

- 1) Prepare a system one-line diagram showing all elements to be included in the analysis. The diagram should provide significant details to allow the user to identify the system nodes (buses) that will be considered in the short-circuit analysis. Transformers should be drawn with a transformer symbol, motors with a motor symbol, and so on. Depending on the complexities of the system drawing, the amount of equipment detail shown will vary. However, too much data will make it difficult to locate any item of concern. A separate equipment list can be used to reduce the data placed on the one-line diagram.

- 2) Prepare an impedance diagram showing the system impedances. Most engineers show impedance in per-unit on a common MVA base. However, ohms can be used if the voltage for each bus is also given. To reduce the amount of drafting time, the one-line diagram may be used together with the equipment list identifying the impedance data for the various components shown on the one-line diagram. Many computer programs allow the use of "raw" data to be used, thus eliminating the need for the impedance diagram.
- 3) Develop an equivalent circuit of the "outside world." This circuit represents the part of the system for which short-circuit calculations are not required, but its effect on the total fault current is important and must be included. In the analysis of industrial and commercial power systems, the utility system is often represented as an equivalent circuit.
- 4) Calculate the symmetrical short-circuit current at the buses of concern. This can be done by hand using the techniques given in the following sections and chapters or with a computer program. Chapter 4 through Chapter 6 provide details on solving for symmetrical short-circuit currents.
- 5) Apply appropriate multiplying factors to symmetrical short-circuit currents, as required to reflect the asymmetry of the short-circuit current. First-cycle and interrupting time calculations may need multipliers if used for equipment evaluation, while "30 cycle" calculations used mainly for time delay relay settings may not. See Chapter 10 through Chapter 12 for the application of multiplying factors.
- 6) Compare the calculated short-circuit duties to the equipment ratings. Chapter 11 provides detail on application of short-circuit calculations.

3.4 One-line diagram

When preparing the data for short-circuit studies the first step is to develop a one-line diagram of the electrical system. In a balanced three-phase system, the circuit impedance for each phase is the same as for the other two phases. This symmetrical property is taken advantage of by drawing the electrical system as a single-phase drawing. This drawing is referred to as a "one-line." Standard symbols from ANSI Y32.2-1975 or IEC 117 are used to represent electrical apparatus. Figure 3-4a, Figure 3-4b, and Figure 3-4c provide the more commonly used symbols. The drawing should include all sources of short-circuit current, (utilities, generators, synchronous motors, induction motors, condensers, etc.), and all significant circuit elements, (transformers, cables, circuit breakers, fuses, etc.).

In developing the one-line diagram, the engineer must decide how much detail should be represented. Too much data can make the drawing cluttered and hard to read. For example, transformers can be labeled with the voltage rating, tap, kVA, and impedance, or be limited to the kVA rating and the percent impedance.

Item	ANSI		IEC	
	Symbol	Alternate	Symbol	Alternate
High Voltage Breaker		 Draw Out		 Draw Out
Low Voltage Breaker		 Draw Out Series Trip Network Protector Thermal Overload		 Draw Out Series Trip Thermal Overload
Transformer 2 Windings		 LTC LTC		 LTC
Transformer 3 Windings		 LTC LTC		 LTC

Figure 3-4a—Typical symbols used on one-line diagrams

Item	ANSI		IEC	
	Symbol	Alternate	Symbol	Alternate
Resistor				
Capacitor				
Reactor		 Iron Core Topped		 Topped Topped
Fuse		 Draw Out Draw Out		 Fused Switch Fused Switch
Switch		 NO NC Double Throw		 NO NC NC

Figure 3-4b—Typical symbols used on one-line diagrams

Item	ANSI		IEC	
	Symbol	Alternate	Symbol	Alternate
Contactor		 Fused Thermal Overload		 Fused Thermal Overload
Generator		 EXH G		 EXH G
Motor		 H H I Induction S Synchronous		 H H I Induction S Synchronous

Figure 3-4c—Typical symbols used on one-line diagrams

3.4.1 Single-phase equivalent circuit

The single-phase equivalent circuit is a tool for simplifying the analysis of balanced three-phase circuits, yet it is the solution method for which the restraints are probably most often disregarded (see Griffith [B4]). Its use is best understood by examining a three-phase diagram of a simple system and its single-phase equivalent, as shown in Figure 3-5. Also illustrated is the popular one-line diagram representation that is commonly used to describe the same three-phase system on drawings.

For a three-phase system known to have perfectly balanced symmetrical source excitation (voltage), loads, and shunt and series line impedances connected to all three phases (upper diagram), the neutral conductor (shown dotted), whether physically present or inserted for mathematical convenience, will carry no current. Under these conditions, the system can be accurately described by either of the two lower diagrams of Figure 3-5. The single-phase equivalent circuit is useful because the solution to the classical loop equations is much easier to obtain than for the more complicated three-phase network.

In the discussion that follows, it is assumed that there is no coupling between phases of the loads and power delivery equipment. Such coupling would not allow a “decoupled” analysis of one phase of the balanced circuit. Symmetrical component techniques (to be described later) can effectively decouple the three-phase circuits, assuming balanced (equal) coupling between phases, into zero, positive, and negative sequence equivalent circuits. Under balanced three-phase operating conditions, it can be shown that an analysis of the positive sequence equivalent circuit gives results that are identically equal to “a”

phase values. For this reason, the concepts of “per phase,” “single-phase,” and “positive sequence” analysis are often used interchangeably. Note that this usage is not rigorously correct and can lead to confusion. The references should be consulted for a complete development of the equivalence (or lack thereof) of these various descriptive terms.

In determining the complete short-circuit solution, the other two phases will have responses that are shifted by 120° and 240° , but are otherwise identical to that of the reference phase.

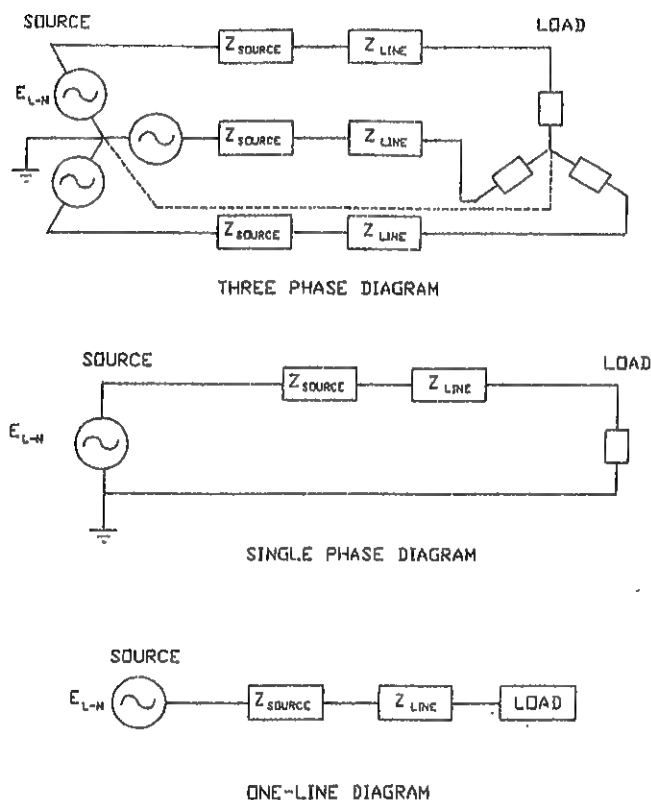


Figure 3-5—Electrical power diagrams

Anything that upsets the balance of the network renders the model invalid unless special calculating techniques are used. One instance for which this might occur is the line-to-ground fault shown in Figure 3-6. For this fault condition, the balance or symmetry of the circuit is destroyed. Neither the single-phase equivalent circuit nor the one-line diagram representation is valid. The single phase and the one-line diagram representations would imply that the load has been disconnected. However, it continues to be energized by two-phase power as shown on the three-line diagram. So called “single-phase operation” of

three-phase equipment can cause serious damage to motors and may also result in unacceptable operating condition of certain load apparatus.

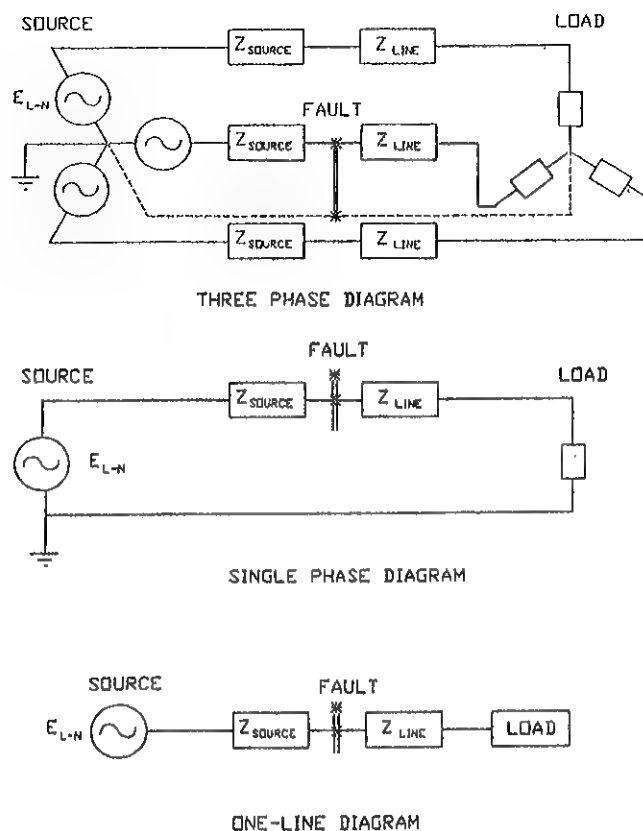


Figure 3-6—Electrical power diagrams showing fault location

3.4.2 Bus numbers

Some short-circuit analysis computer programs require the use of bus numbers identifying each individual bus on the one-line diagram to assist the engineer with the printed computer results. When bus numbers are required, each element of the electrical system must be between two distinct bus numbers. The one-line diagram is divided into circuit segments by assigning bus numbers as follows:

- To a bus with three or more connections to it. These often are pieces of major equipment such as switchgear buses, motor control center buses, substations, etc.
- At utility ties and generator terminals.
- At the terminals of motors when the cable connection to the motor is represented.

Sometimes it is convenient to place bus numbers at the junction point of two different elements such as a cable connection to a transformer if the computer program can handle a

large number of nodes. In other cases, the series per-unit impedances are added together and represented as a single element in the program. Care must be taken when combining series impedances to ensure that any impedance modifiers are applied to the correct elements. For example, in performing first-cycle and interrupting time fault calculations, the motor impedances are modified. If the cable impedance is included in the motor impedance, it should not be modified. Likewise, if transformer taps are to be changed, the cable should be represented as a single element between two buses.

3.4.3 Impedance diagrams

The companion document to the one-line diagram for short-circuit calculations is an impedance diagram. It is basically the same as the one-line diagram with each significant circuit element replaced by its respective impedance. Figure 3-8 is the impedance diagram for the electrical system shown in Figure 3-7. This drawing is a useful reference document. To reduce the quantity or size of drawings, only the one-line diagram is truly required, but it must be supplemented with tables providing the impedance data.

3.4.4 Short-circuit flow diagrams

The short-circuit flow diagram is a one-line diagram showing direction and magnitude of short-circuit currents flowing in the connecting branches for a specific system short circuit. These diagrams usually are an expanded view of one section of the one-line diagram to show the results of a short-circuit calculation.

3.4.5 Relaying one-line diagrams

The relaying one-line diagram is a one-line diagram with current transformers, potential transformers, relay device function numbers or relay types shown. Details as to which breaker the relay trips is sometimes given. Rather than placing all this detail on one system drawing, a relay one-line is often provided for each substation or switchgear drawing.

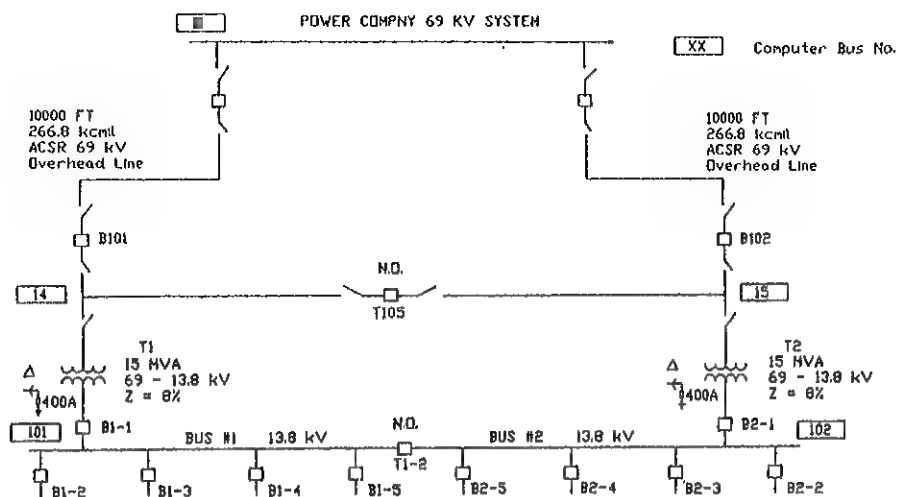


Figure 3-7—One-line diagram with bus numbers

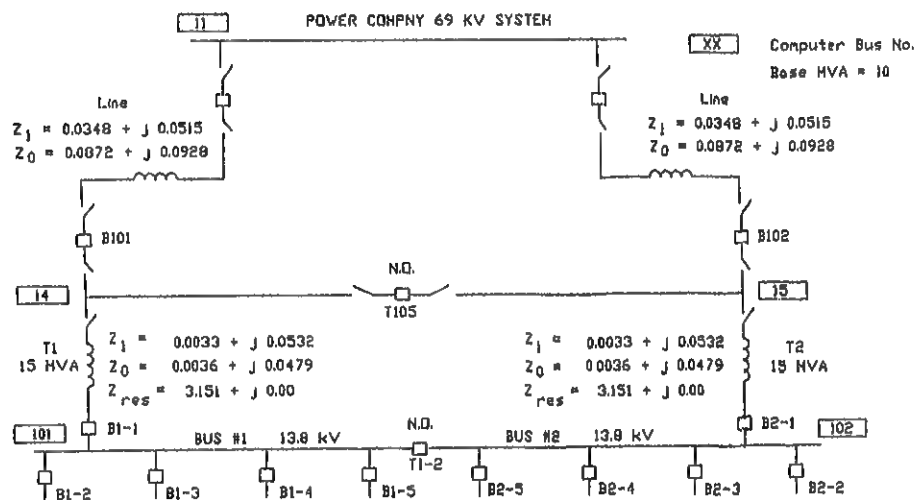


Figure 3-8—Impedance one-line diagram

3.5 Per-unit and ohmic manipulations²

Short-circuit calculations are made to solve the equation $I = E/Z$. Obtaining values of the impedance Z is a time consuming effort when conducting a short-circuit analysis. The impedance Z , given on the equipment nameplate or furnished by the equipment manufacturer, may be identified either in per-unit or in ohmic values, but one or the other must be used consistently in any calculation. The same study results will ultimately be obtained for either ohmic or per-unit representation. Many engineers find the per-unit system easier to use because impedance changes due to transformer ratios are automatically taken into account. The per-unit system is a shorthand calculating technique where all equipment and circuit impedances are converted to a common base.

In using the ohmic system, all impedances must be referred to the appropriate voltage level by the square of the transformer turns ratio. With several levels of voltages, this can become an added bookkeeping task. In the per-unit system, changing of impedance values because of transformer ratios is unnecessary. For example, using the same voltage base as the transformer primary and secondary voltages results in the transformer per-unit impedance being the same on both sides of the transformer. Equipment manufacturers usually state the impedance of electrical equipment in per-unit on the kVA and voltage base of the equipment.

The per-unit impedances of machines (using the machine ratings as bases) of the same type (induction motor, synchronous motor, synchronous generator, etc.) are approximately the same for a broad range of machine sizes, while the ohmic values vary with the size of the machine. Knowing that the per-unit impedances fall within a fairly narrow band is advantageous when machine data must be estimated. Typical per-unit values are often used in preliminary designs or for small motors where individual test reports are not available.

In the per-unit system, there are many base quantities, including base apparent power (kVA or MVA), base volts (volts or kV), base impedance (ohms), and base current (amperes). Choosing any two automatically determines the other bases. The relationship between base, per-unit, and actual quantities is as shown in Equation (3.8).

$$\text{per quantity unit} = \frac{\text{actual quantity}}{\text{base quantity}} \quad (3.8)$$

or rewritten

$$\text{actual quantity} = (\text{per unit quantity})(\text{base quantity}) \quad (3.9)$$

Normally, the base MVA is selected first and the most commonly used MVA bases are 10 MVA and 100 MVA, although any MVA or kVA base value may be used. Many utilities express impedance as "percent" impedance on a 100 MVA base, where percent impedance equals per-unit impedance times 100. The voltage at one level is chosen as the

²See Beeman [B1], Stevenson [B10], Weedy [B11].

base voltage, which then determines the base voltage at the other levels using the primary and secondary operating voltage rating of the transformers. Rated transformer primary and secondary voltages are commonly used as the voltage bases.

For three-phase power systems, line-to-line voltage (usually expressed in kV) is used with three-phase kVA or MVA base. The following equations apply to three-phase systems. Equation (3.10) and Equation (3.11) convert the equipment and line data to a common base when the base voltages match the equipment voltages.

Converting ohms to per-unit impedance:

$$Z_{pu} = \frac{Z_{ohms} MVA_{base}}{kV_{LL}^2 Base} \quad (3.10)$$

Converting per-unit ohms from an equipment MVA base to a common MVA base where base voltage = equipment voltage:

$$Z_{Common\ base} = \frac{Z_{Equipment\ base} MVA_{Common\ base}}{MVA_{Equipment\ base}} \quad (3.11)$$

Converting per-unit ohms from an equipment voltage base to a common voltage base:

$$Z_{Common\ base} = Z_{Equipment} \frac{kV_{LL\ Equipment}^2}{kV_{LL\ Common}^2} \quad (3.12)$$

Combining Equation (3.11) and Equation (3.12):

$$Z_{Common\ base} = Z_{Equipment} \frac{(MVA_{Common\ base})(kV_{LL\ Equipment\ base}^2)}{(MVA_{Equipment\ base})(kV_{LL\ Common\ base}^2)} \quad (3.13)$$

Having determined the MVA and voltage bases, the current and impedance bases for each voltage level can be determined. This provides a constant multiplier at each voltage level to obtain the current or per-unit impedance by the use of Equation (3.9).

$$I_{Base(amps)} = \frac{(MVA_{Base})1000}{\sqrt{3} kV_{LL}} \quad (3.14)$$

$$Z_{Base(ohms)} = \frac{(kV_{LL}^2)1000}{kVA} = \frac{kV_{LL}^2}{MVA} \quad (3.15)$$

Similar expressions can be used for a single-phase system with care exercised to use only quantities found in single-phase circuits. The current is the line current, the voltage is line-to-neutral voltage, and the base is the single-phase kVA or MVA. For example:

$$Z_{Common\ base} = \frac{Z_{Equipment\ base} MVA_{Common\ base}}{MVA_{Equipment\ base}} \quad (3.11a)$$

Per-unit ohms on equipment voltage base to common voltage base:

$$Z_{Common\ base} = Z_{Equipment} \frac{kV_{LN\ equipment}^2}{kV_{LN\ common}^2} \quad (3.12a)$$

$$I_{Base} = \frac{(MVA_{Base}) 1000}{kV_{LN}} \quad (3.14a)$$

3.6 Network theorems and calculation techniques

The following network theorems and calculating techniques provide the basis for valid methods of solving power system circuit problems.

3.6.1 Linearity

Linearity (see Griffith [B4] and Hoyt and Kennedy [B5]) is the most fundamental concept to be discussed and is a powerful extension of Ohm's Law. Examination of Figure 3-9 will assist in understanding the basic principles. The simplified network is represented by the single impedance element, $R + jX$. The circuit diagram shown is said to be linear for the chosen excitation and response function. A plot of the response magnitude (current) versus the source excitation magnitude (voltage) is a straight line for a linear element. This is the situation shown for plot "A" (solid line) in the graph at the bottom of the figure. When linearity exists, the plot applies to either the steady-state value of the excitation and response functions or the instantaneous value of the functions at a specific time.

When linear dc circuits are involved, the current will double if the voltage is doubled. The linear characteristic also holds for ac circuits provided the frequency of the driving voltage is held constant. In a similar manner, it is possible to predict easily the response of a constant impedance circuit (i.e., constant R , L , and C elements) to any magnitude of dc source excitation or fixed frequency sinusoidal excitation based on the known response at any other level of excitation. For the chosen excitation function of voltage and the chosen response function of current, either dotted curve "B" or "C" would be examples of the response characteristic of a non-linear element. Such nonlinear characteristics are often encountered in the modeling of rotating machines and transformers, and the engineer must be aware of the potential effects.

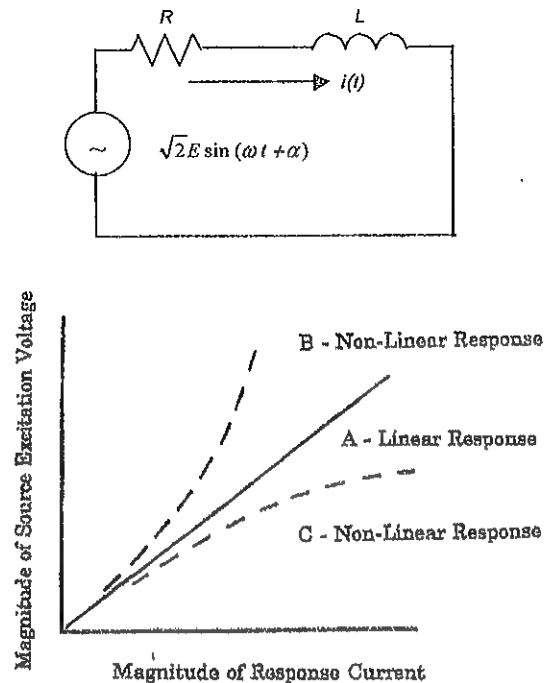


Figure 3-9—Linearity

An important limitation of linearity is that the excitation source, if not independent, must be linearly dependent on another (independent or dependent) source or network variable. Ultimately in a linear circuit, all variables, including source, network, and load voltages and currents are related to each other by a set of coefficients. This restraint, in effect, forces a source to behave with a linear response.

3.6.2 Superposition

Superposition (see Griffith [B4] and Hoyt and Kennedy [B5]) is possible as a direct result of linearity and hence is subject to the same restraints. The superposition theorem states that if a network consists of linear elements and has several dc or fixed frequency ac excitation sources (i.e., voltages), the total response (i.e., current) can be evaluated as the sum of the currents caused by each voltage source acting separately with all other source voltages reduced to zero or, similarly, all other current sources open circuited. Note that this sum will be a simple algebraic sum in dc circuits and will be a vector sum in ac circuits.

An example that illustrates this principle is shown in Figure 3-10. The written equation is for the sum of the currents from each individual source of $V = 10\text{ V}$ and $V = 5\text{ V}$. The 2 ohm and 6 ohm impedance values represent the sum of internal impedances of the voltage sources and any other impedance in the source branches. The 5 ohm impedance represents a load impedance.

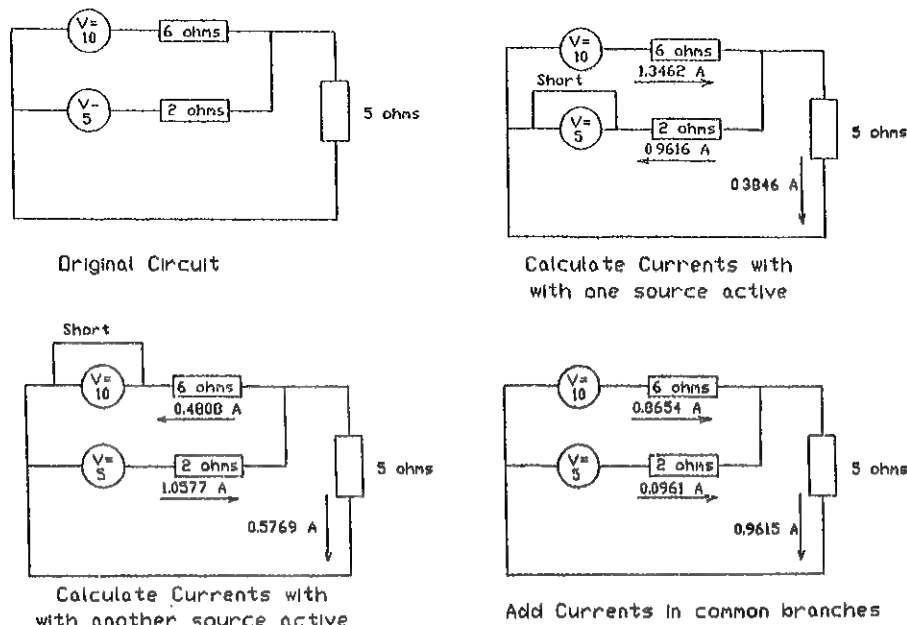


Figure 3-10—Superposition

3.6.3 Thevenin equivalent circuit

This powerful circuit analysis tool is based on the fact that any active linear network, however complex, can be represented by a single voltage source equal to the open-circuit voltage across any two terminals of interest, in series with the equivalent impedance of the network viewed from the same two terminals with all sources in the network inactivated (i.e., voltage sources zero and current sources open). The validity of this representation requires only that the network be linear. The existence of linearity is, therefore, a necessary restraint. (Note that Thevenin equivalents can also be formed for multiphase power systems.) The application of the Thevenin equivalent circuit can be appreciated by again referring to the simple circuit of Figure 3-11 and developing the Thevenin equivalent for the network with the switch in the open position as illustrated in the step-by-step procedure. After connecting the 5-ohm load to the Thevenin equivalent network, the solution is the same as in Figure 3-10, 0.9615 amperes. Using the simple Thevenin equivalent shown for the entire left side of the network, it would be easy to examine the response of the circuit as the value of the load impedance is varied. Caution, however, is required to ensure that equipment models or buses of interest are not “absorbed” by the process of forming a Thevenin equivalent. Once absorbed, relevant data pertaining to individual contributions to total short-circuit current and bus voltages are unrecoverable without completely resolving the entire circuit without using an equivalent.

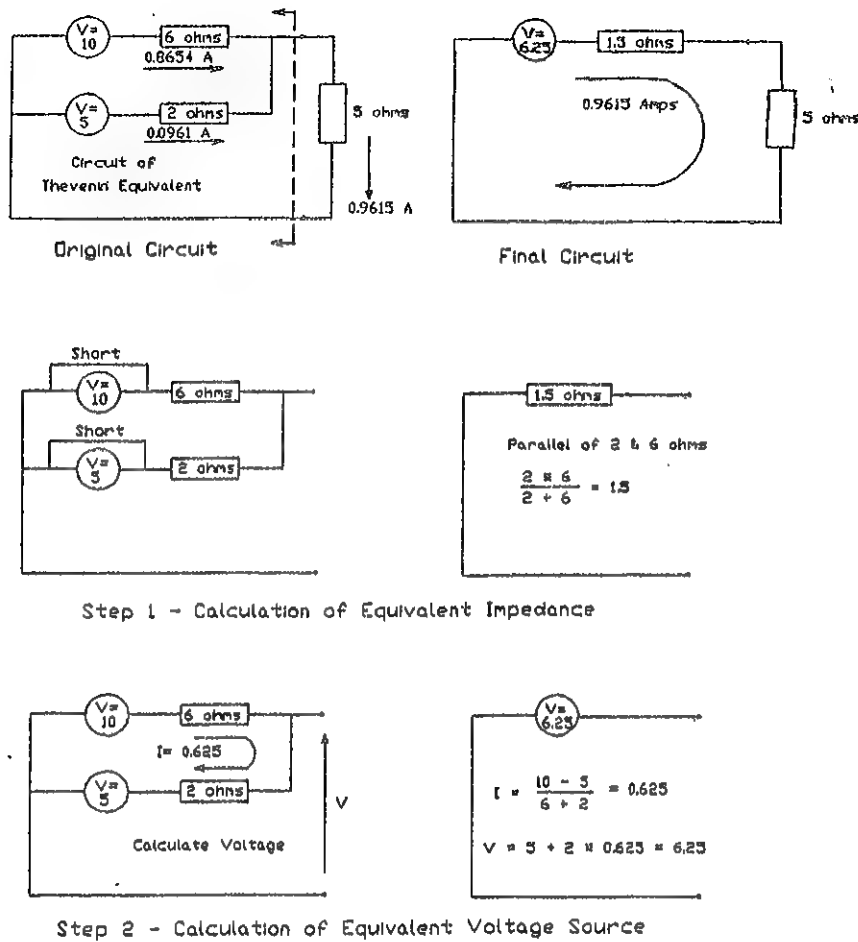


Figure 3-11—Thevenin equivalent

The Thevenin equivalent circuit solution method is equally valid for complex impedance circuits and is the basis for making short-circuit calculations. The actual values for the source voltage and branch impedances would, no doubt, be substantially different from those used in this example.

In the sample circuit, the 2-ohm branch of the circuit could correspond to the utility supply through a transformer, while the 6-ohm branch may represent a generator connected to the load bus. A bus fault shorting out the load will result in a current of $6.25/1.5 = 4.1667$ A.

The network shown in Figure 3-11 may well serve as an oversimplified representation of a power system equivalent circuit. As previously mentioned, if the terminals experience a bolted fault, without knowing the details of the original circuit, there is no way of knowing which fraction of the total circuit is supplied from each source in the original circuit.

3.6.4 Norton equivalent circuit

A Norton equivalent, Figure 3-12, that consists of a current source (triangle) in parallel with an equivalent impedance can alternately be developed for the Thevenin equivalent circuit. This representation is often used for computer solutions, but generally not for “by hand” solutions in power system analysis work.

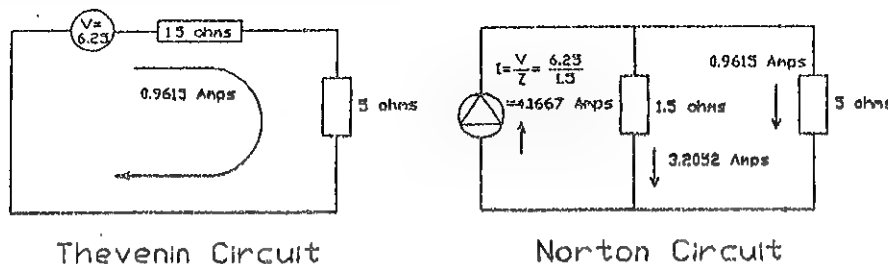


Figure 3-12—Norton equivalent for a Thevenin equivalent circuit

3.6.5 Millman's theorem

A direct result of Norton's equivalent is Millman's theorem (see Fich and Potter [B3]), which states that when any number of voltage sources of arbitrary generated voltage and finite internal impedance different from zero are connected in parallel, the resultant voltage across the parallel combination is the ratio of the algebraic sum of the currents that each source individually delivers when short circuited to the algebraic sum of the internal admittances. Millman's theorem can be used to simplify calculations in polyphase circuits and has other applications.

3.6.6 Reciprocity

The general reciprocity (see Fich and Potter [B3]) theorem states that in networks consisting of linear circuit elements, the ratio of excitation to response when only one excitation is applied is constant when the positions of excitation and response are interchanged. Specifically, this means that the ratio of the voltage applied in one branch to the resulting current in a second branch of a network is the same as the ratio of the voltage applied in the second branch to the resulting current in the first branch.

3.6.7 The sinusoidal forcing function³

It is a most fortunate truth that the excitation sources (i.e., driving voltage) for electrical networks, in general, have a sinusoidal character and may be represented by a sine wave plot of the type as previously illustrated in Figure 3-2 and Figure 3-3. There are two important consequences of this circumstance. First, although the response (i.e., current) for a complex R , L , C network represents the solution to at least one second-order

³See Griffith [B4].

differential equation, the steady-state result will be a sinusoid of the same frequency as the excitation and differs only in magnitude and phase angle.

The second important item is that when the sinusoidal current is forced to flow in a general impedance network of R , L , and C elements, the voltage drop across each element will have a sinusoidal shape of the same frequency as the source. The sinusoidal character of all the circuit responses makes the application of the Superposition technique to a network with multiple sources surprisingly manageable. The necessary manipulation of the sinusoidal terms is easily accomplished using the laws of vector algebra.

The only restraint associated with the use of the sinusoidal forcing function concept, is that the circuit must be comprised of linear elements. While most circuits contain nonlinearities, it is usually possible to restrict an analysis to a certain range of operating conditions where linear characteristic hold.

3.6.8 Phasor representation

Phasor representation allows any sinusoidal forcing function to be represented as a phasor in a complex coordinate system in the manner shown in Figure 3-13 (see Griffith [B4]). The expression for the phasor representation of a sinusoid may assume any of the following shorthand forms:

Exponential: $Ee^{j\phi}$

Rectangular: $E(\cos\phi + j\sin\phi)$

Polar: E/ϕ

These three forms are related as shown below.

$$Ee^{j\phi} = E(\cos\phi + j\sin\phi) = E\angle\phi$$

The network impedances can be represented as phasors using vectorial relationships and the circuit current responses can be obtained through the simple vector algebraic manipulation of the quantities involved. The need for solving complex differential equations in order to determine the steady-state circuit response is completely eliminated.

The following restraints apply:

- 1) The sources must all be sinusoidal.
- 2) The frequency must remain constant.
- 3) The circuit R , L , and C elements must remain constant, i.e., linearity must exist.

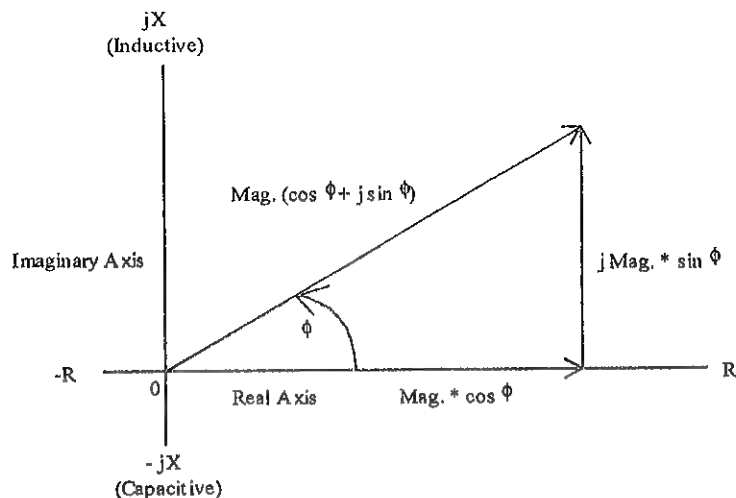


Figure 3-13—The phasor diagram

3.6.9 Fourier representation⁴

This tool allows any non-sinusoidal periodic function to be represented as the sum of a dc component and a series (infinitely long, if necessary) of ac sinusoidal functions. Figure 3-14 shows a non-sinusoidal waveform without a dc component. The ac components have frequencies that are an integral “harmonic” of the fundamental frequency. The general mathematical form of the so-called “Fourier Series” is shown in Equation (3.15).

$$f(t) = F_0 + \sum_{n=1}^{\infty} \sqrt{2} F_n \cos(n2\pi f_0 t + \theta_n) \quad (3.15)$$

where F_0 is a dc term, F_1 is a fundamental frequency (60 Hz in North American power systems) term, and F_n are called “harmonics” of the fundamental and have frequency of $n2\pi f_0$. Each harmonic may have some nonzero phase angle θ_n .

⁴See Griffith [B4].

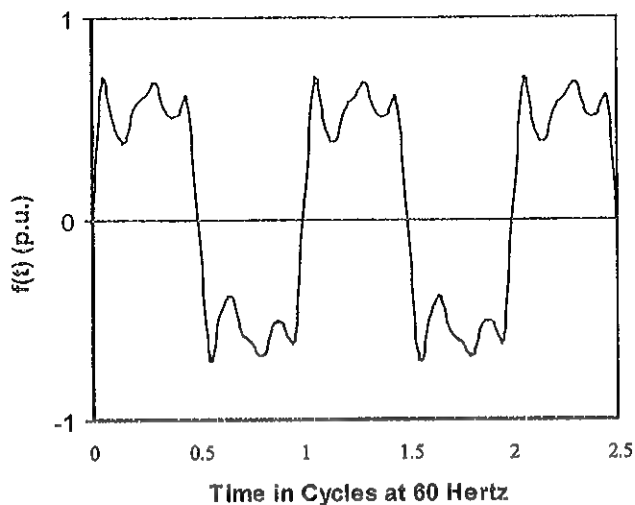


Figure 3-14—The Fourier representation

The importance of the Fourier representation is that the response to the original driving function can be determined by first appropriately solving for each harmonic component driving function and then summing all the individual solutions to find the total response by superposition. Because each of the component response solutions is readily obtained, the most difficult part of the problem becomes the modification of reactance and capacitance of the network for each harmonic and the solution of the component driving function. The individual harmonic voltages can be obtained in combination with numerical integration approximating techniques through several well-established mathematical procedures. The discussion of their use is better reserved for the many excellent texts on the subject.

There are several rather abstract mathematical conditions that must be satisfied to permit the use of a Fourier representation. The practical restraints are that the original driving function must be periodic (repeating) and the network must remain linear for each of the frequencies in the non-sinusoidal wave form.

3.6.10 Equivalence

The Equivalence Theorem (see Fich and Potter [B3]) states that at any given frequency, any passive four-terminal network can be replaced by an equivalent star or delta network. This fact is very useful in short-circuit calculations to reduce a system consisting of many current loops and voltage nodes to a simple equivalent circuit. Figure 3-15 shows the equations for both delta-star and star-delta transformations.

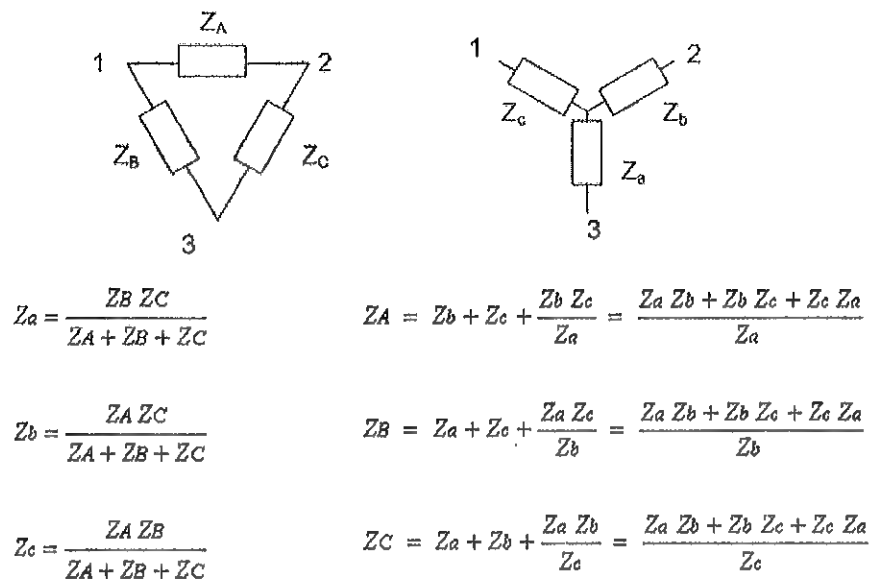
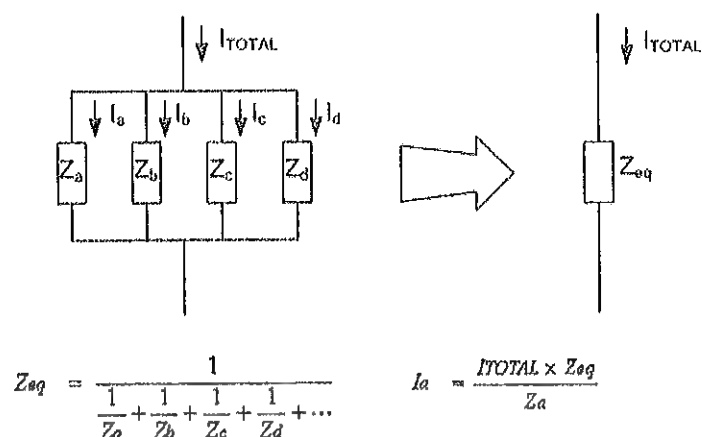


Figure 3-15—Delta-star impedance conversions

3.6.11 Parallel impedances

Where two or more impedances are paralleled and Z_{equiv} , equals the equivalent impedance, the relationships shown in Figure 3-16 are valid. In the case of two impedances, the expression is reduced to the product of the two impedances divided by the sum.



With only two impedances in parallel -

$$Z_{eq} = \frac{Z_a \times Z_b}{Z_a + Z_b} \quad I_a = \frac{I_{TOTAL} \times Z_b}{Z_a + Z_b}$$

Figure 3-16—Parallel impedances

3.6.12 Analysis of unbalanced faults using symmetrical components⁵

An unbalanced fault condition is the most common circuit condition that invalidates the single-phase (or positive sequence) equivalent circuit condition method for calculating short-circuit current. The use of symmetrical components is the analytical technique most commonly used under these circumstances. Unbalanced faults, such as line-to-ground faults, line-to-line faults, and double line-to-ground faults require the use of symmetrical components for the calculation of the short-circuit currents. Symmetrical components are used to reduce an unbalanced system of phasors into three balanced systems of phasors designated as positive, negative, and zero sequence components. Figure 3-17 is an illustration of the system of symmetrical components. The subscripts A, B, and C represent the three phases of voltage and the subscripts 1, 2, and 0 represent the positive, negative, and zero sequence components.

⁵See Stevenson [B10], Westinghouse [B12], Rothe [B9].

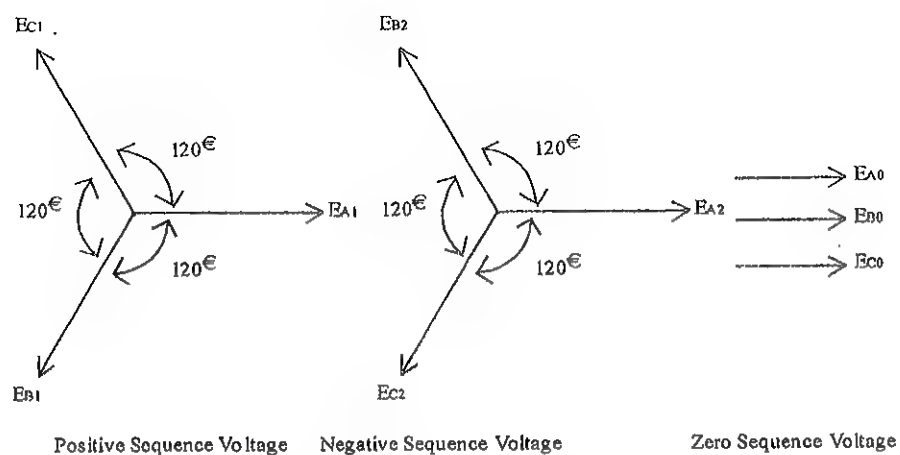


Figure 3-17—Symmetrical component balanced phasors

Any three-phase set of unbalanced voltage phasors (or current phasors) can be resolved into three balanced or symmetrical sets of phasors, i.e., positive sequence symmetrical components, negative sequence symmetrical components, and zero sequence components, as shown in Figure 3-18.

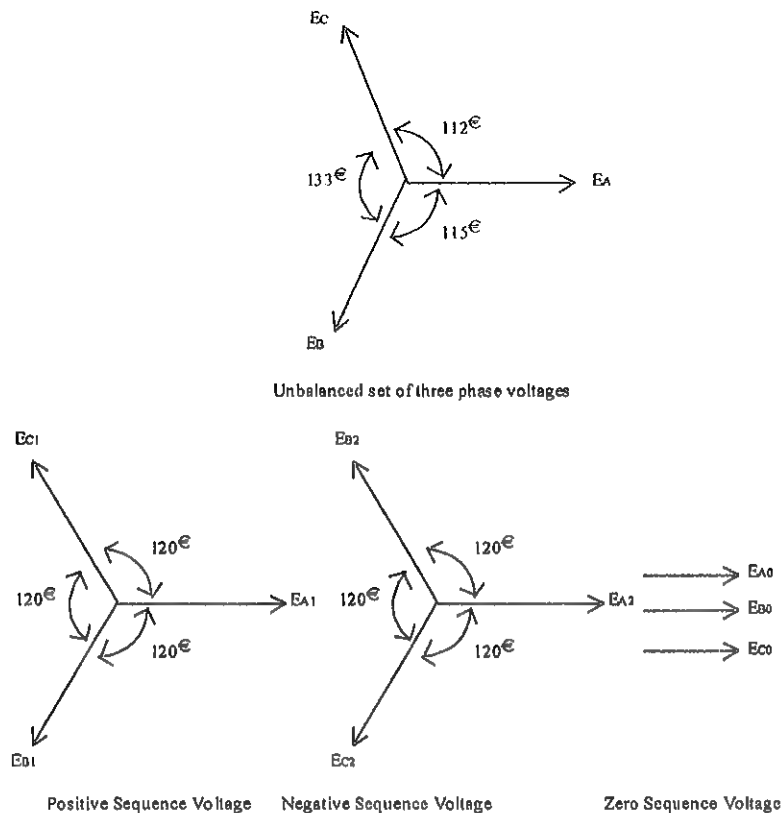


Figure 3-18—Symmetrical components of unbalanced phasors

The use of symmetrical components in fault analysis is covered in more detail in Chapter 11.

Symmetrical component techniques allow the user to solve for voltages and currents in balanced sequence networks, and then convert the solution back to actual currents and voltages. The relationship between the phase quantities in terms of their symmetrical components is given below. Values of current can be substituted in place of the voltage in the equation without any conversion factors. The equations are normally given as a set of three to represent the individual phases [Equation (3.16)].

$$\begin{aligned}
 E_a &= E_{a0} + E_{a1} + E_{a2} = E_{a0} + E_{a1} + E_{a2} \\
 E_b &= E_{b0} + E_{b1} + E_{b2} = E_{a0} + E_{a1} \angle 240^\circ + E_{a2} \angle 120^\circ \\
 E_c &= E_{c0} + E_{c1} + E_{c2} = E_{a0} + E_{a1} \angle 120^\circ + E_{a2} \angle 240^\circ
 \end{aligned} \tag{3.16}$$

When using symmetrical components it is convenient to define an operator “a” such that:

$$a = 1 \angle 120^\circ = -0.5 + j0.866$$

$$a^2 = 1 \angle 240 = -0.5 - j0.866$$

Note that vector “a” is an operator with unit length and is oriented 120 degrees in counter-clockwise rotation from reference axis. Figure 3-19 shows the property of a_0 , a_1 , and a_2 and so on.

Using the operator “a” Equation (3.16) can now be rewritten as shown in Equation (3.17):

$$\begin{aligned} E_a &= E_{a0} + E_{a1} + E_{a2} \\ E_b &= E_{a0} + a^2 E_{a1} + a E_{a2} \\ E_c &= E_{a0} + a E_{a1} + a^2 E_{a2} \end{aligned} \quad (3.17)$$

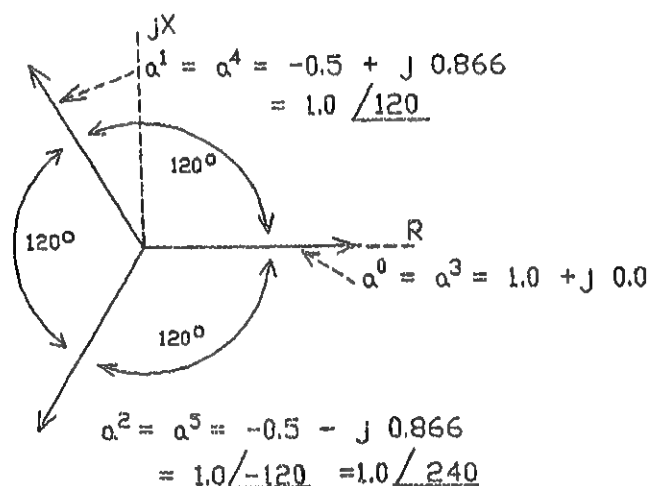


Figure 3-19—Operator “a” vectors

or in matrix form as in Equation (3.18):

$$\begin{bmatrix} E_A \\ E_B \\ E_C \end{bmatrix} = \begin{bmatrix} 1 & 1 & 1 \\ 1 & a^2 & a \\ 1 & a & a^2 \end{bmatrix} \begin{bmatrix} E_{a0} \\ E_{a1} \\ E_{a2} \end{bmatrix} \quad (3.18)$$

with the matrix A defined as follows in Equation (3.19):

$$[A] = \begin{bmatrix} 1 & 1 & 1 \\ 1 & a^2 & a \\ 1 & a & a^2 \end{bmatrix} \quad (3.19)$$

The inverse of the A matrix is as shown in Equation (3.20):

$$[A]^{-1} = \frac{1}{3} \begin{bmatrix} 1 & 1 & 1 \\ 1 & a & a^2 \\ 1 & a^2 & a \end{bmatrix} \quad (3.20)$$

and

$$\begin{bmatrix} E_{a0} \\ E_{a1} \\ E_{a2} \end{bmatrix} = \frac{1}{3} \begin{bmatrix} 1 & 1 & 1 \\ 1 & a & a^2 \\ 1 & a^2 & a \end{bmatrix} \begin{bmatrix} E_A \\ E_B \\ E_C \end{bmatrix} = [A]^{-1} \begin{bmatrix} E_A \\ E_B \\ E_C \end{bmatrix} \quad (3.21)$$

The equations above were written for the sequence voltages. A similar set of equations can be written for the sequence current by interchanging the voltage symbol for a current symbol. Note that if the zero sequence quantity, I_{a0} (or V_{a0}), equals zero then the vector sum of $I_A + I_B + I_C$ (or $V_A + V_B + V_C$) equals zero.

In the use of symmetrical components, the voltage is normally taken as line-to-neutral voltage for the following reason. In an unbalanced set of E_{L-L} voltage vectors, the sum of voltages around the vector triangle is zero and the identity of zero sequence is not apparent. Based on Equation (3.21), the zero sequence E_{L-L} is zero, $E_{a0} = E_{AB} + E_{BC} + E_{CA}$; however, E_{a0} using E_{L-N} voltage may not be zero. The vector diagram in Figure 3-20 illustrates the point.

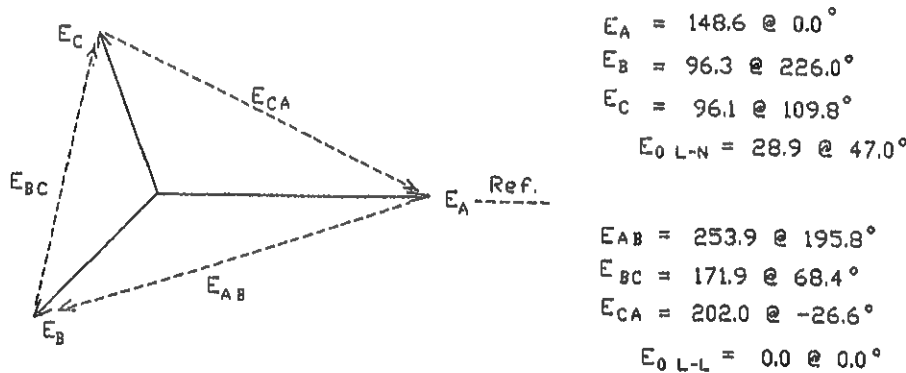


Figure 3-20—Zero sequence component of line-to-line and line-to-neutral voltages

In a grounded power system, the zero sequence impedance completes the circuit by allowing the current to flow in the system neutral or in ground. The magnitude of current in the return path is $3I_{a0}$. Where $3I_{a0} = I_n = I_a + I_b + I_c$. When $3I_{a0} = 0 = I_a + I_b + I_c$, no current flows in the neutral. Note that a three-phase three-wire (ungrounded) system will require $I_{a0}=0$ because no neutral (or return) path exists for current flow.

It is interesting to note that the delta winding of a delta-wye or wye-delta connected transformer or delta connected loads provide no current path to neutral and no zero sequence currents will exist in delta connected systems. However, it can be shown that zero sequence circulating currents can exist in the delta winding of a transformer but not pass through the transformer.

3.6.13 Sequence impedances

The impedance of elements in a symmetrical electrical system may be resolved into positive, negative, and zero sequence components. In a balanced three-phase system, only positive sequence impedances are required and only positive sequence voltage drops and current flows result from the analysis. (Recall the equivalence of the positive sequence and the “a” phase under balanced three-phase conditions.) In systems where the phase impedances are not equal or where unbalanced faults are simulated using symmetrical networks, positive, negative, and perhaps zero sequence voltage drops and current flows will result.

The relationships between sequence voltages and currents follow Ohms’ law as shown in Equation (3.22) and Figure 3-21 below.

$$\begin{aligned} E_1 &= I_1 Z_1 \\ E_2 &= I_2 Z_2 \\ E_0 &= I_0 Z_0 \end{aligned} \tag{3.22}$$

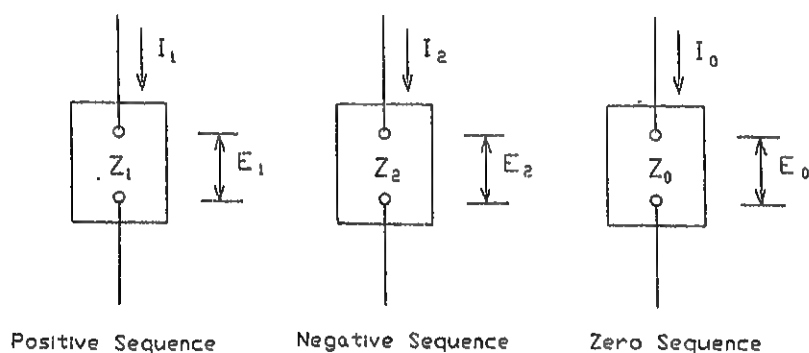


Figure 3-21—Sequence network diagrams for Equation (3.22)

In general, the impedances of static elements are the same in positive and negative sequences, but may differ in the zero sequence. For rotating machines, the impedances are usually different for all sequences.

Rothe [B9], Stevenson [B10], and Westinghouse [B12] provide positive, negative, and zero sequence impedance representations of the various system components for network calculations.

Figure 3-22 illustrates how sequence components are obtained for a transformer. The same source connection is used for other equipment. Positive sequence impedances are determined by the use of a balanced three-phase source while zero sequence impedances are determined by connecting all three-phase leads to a common single-phase source.

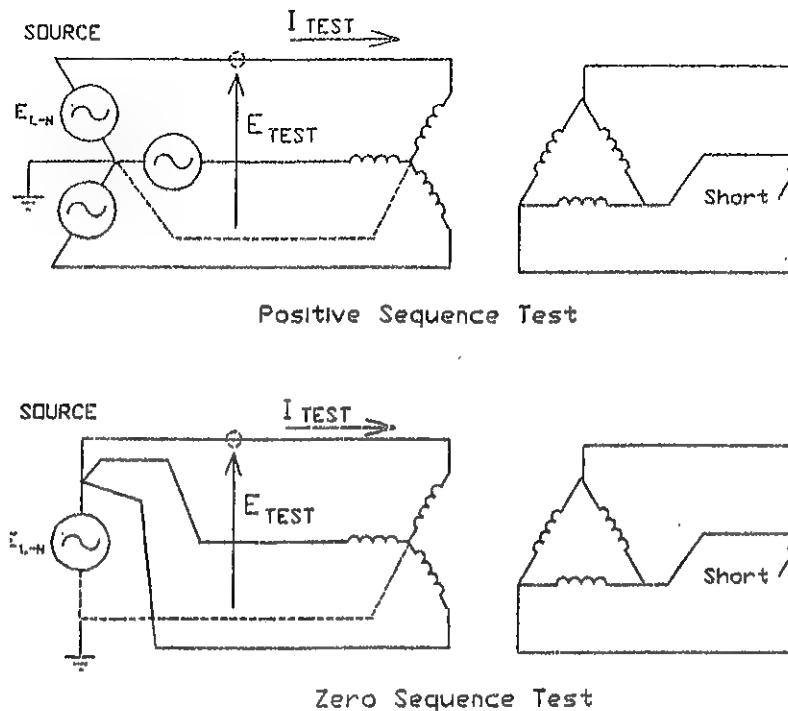


Figure 3-22—Test set-up used to obtain the sequence components of a transformer

3.7 Extending a three-phase short-circuit calculation procedures program to calculate short-circuit currents for single-phase branches

The following describes the extension of a three-phase short-circuit calculation techniques program to include fault current calculations for single-phase branch circuits supplied line-to-line by a three-phase system. The procedure for the special system limitation given below prevents the need to use symmetrical components.

The procedure assumes that the three-phase system is not appreciably unbalanced by the single-phase branches, further that there are no single-phase rotating machines contributing to the short-circuit duty, and that positive and negative sequence impedances are equal. The latter assumption suggests that procedure is applied with reasonable accuracy only to first-cycle short-circuit calculations when the contribution from three-phase rotating machines is important because machine positive sequence impedances become greater than negative as time passes.

The procedure has two steps. First, special handling of the single-phase circuit input data is necessary and second, applicable results must be multiplied by $\sqrt{3}/2$ (≈ 0.866). This procedure is an expansion oriented toward computer use of a general procedure described in the *Industrial Power Systems Handbook* [B1]. The input data handling is developed for the single-phase branch circuit as shown in Figure 3-23. To obtain these results by computer, all single-phase circuit input impedance data is converted to per-unit on the study three-phase base and a single-phase base voltage equal to the study three-phase line-to-line base voltage. Input data is handled as noted below.

Conversion of single-phase circuit data to per-unit on a three-phase study base requires the following:

- 1) For a two-conductor feeder use the impedance of one conductor (one phase to neutral, NOT the round loop impedance).
- 2) For a single-phase transformer, per unitize the data based on the single-phase kVA base and 0.5 times the nameplate impedance. The transformer X/R ratio used is approximately equivalent to the X/R ratio of a three-phase transformer of 3 times the single-phase kVA.
- 3) For a single-phase reactor "element," enter one half the actual resistance and reactance expressed in ohms or in per-unit.
- 4) The equivalent three-phase calculation results are multiplied by $\sqrt{3}/2$ (≈ 0.866) to obtain the single-phase short-circuit duties. The program bus voltage could also be entered as $1/0.866 = 1.155$ times the line-to-line voltage to obtain the results directly in amperes.

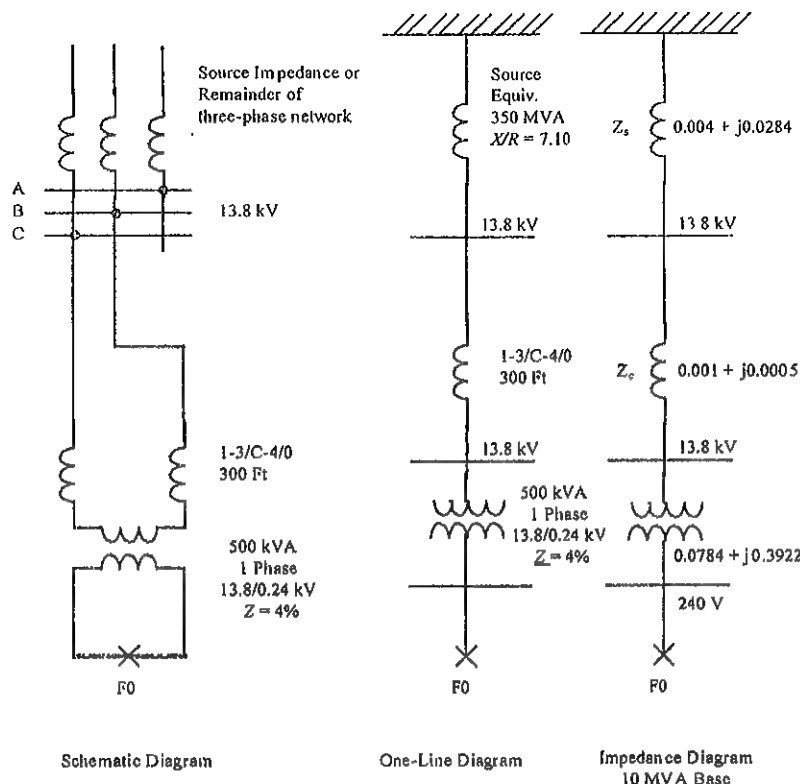


Figure 3-23—Single-phase branch circuit connected line-to-line to a three-phase system. Diagrams show location of single-phase short-circuit at F0.

3.8 Representing transformers with non-base voltages

Occasionally, a power system includes transformers that have voltage ratios that differ from the power system nominal values of base voltage chosen. This difference can have an influence on the calculated fault current levels. The concern is the handling of the transformer impedances and correction due to differences in rated and base voltages. Usually a correction of transformer percent impedance due to a different operating tap other than transformer rated or flat taps is not done unless test data provides this information. Depending upon the design of the tap section of the transformer, the percent impedance of the transformer on other taps is unknown without the transformer tap test data. If there is a change, it is usually not linear or known to vary with any known expression with tap position. Rather than guessing the new value of transformer impedance on other taps, it may be considered a constant.

Several system conditions are possible that will effect the manner in which the transformer per-unit impedance and base voltages are represented in the network. It is

easy for the power system engineer to become frustrated, confused, and not make the necessary corrections. Diagrams in Figure 3-24 and the explanation below should provide some guidance on this subject. On the diagrams, differences from the rated tap, transformer voltage rating, and base voltage of those used in Figure 3-1a are noted with a#. For the condition when the transformer voltages equal the base voltages, nothing needs to be corrected. This includes transformers that are operating off rated taps as shown in Figure 3-1a and Figure 3-24c. In all other cases, there could be an impedance or voltage base change depending on how the calculations are done.

In addition, samples are given where the bus operating voltage is different than the base voltage. Most short-circuit calculations assume the prefault bus voltage is equal to the base voltage when an initial load flow calculation is not made or the procedure in IEEE Std C37.010™ [B8] is followed. In the following examples, the prefault bus voltage is a concern only for that bus. If the primary voltage is high, as shown in Figure 3-24g, there is no change in the 4.16 kV bus fault level. However, a fault on the transformer primary would be affected by the higher 13.8 kV voltage.

Several conditions exist that will affect the degree in which data changes will have to be made to transformers that have voltages or voltage ratios different than the base voltages. These include manual calculations or the use of computer programs that treat all transformers as if they were on rated taps. An example is the condition shown in Figure 3-24e where the transformer rated taps and base voltages are equal, but the transformer tap is not equal to the primary base voltage. For the manual calculation, a base voltage and impedance change are required. Also, there will be many cases where no transformer impedance change or base voltage change will be required; these are automatically handled within the computer program.

Transformer taps can be on either side of the transformer. The need to change the transformer impedance will depend on which side of the transformer the system base voltage is to be held equal to the transformer voltage. In the samples shown, the 13.8 kV (primary side) base voltage was fixed. The sample calculations in the figures use a constant X/R ratio of the source and the transformer to keep calculations simple. In cases where the transformer impedance should be modified before being placed in the network, the expression given in Equation (3.12) (repeated here for convenience) is used. Such a condition occurs when the transformer rated tap voltages do not match base voltages.

$$Z_{\text{Common base}} = Z_{\text{Equipment}} \frac{kV_{LL \text{ Equipment}}^2}{kV_{LL \text{ Common}}^2} \quad (3.12)$$

A special case occurs when one of the transformer rated tap voltages matches the base voltages and the second transformer tap does not. In this case, the easiest procedure is to change the base voltage of the side that does not match so that it does. This is easily done on radial systems and will require other base voltages of equipment to be changed so that all impedances are on the same base. In examples Figure 3-24e and Figure 3-24h, all impedances on the 4.16 kV side of the transformer will have to be placed on a 4.2667 kV base. Other transformers connected to the 4.16 kV system will have 4.2667 kV as one of the base voltages.

For looped systems, it may not be possible to change the base voltage because different transformers could cause a common bus to have a conflicting base voltage. In this case, the procedure is to choose a base voltage, forcing the non-conforming equipment to fit.

Figure 3-24k shows a means of transformer representation to force the base voltage, a method used in many computer programs. If the program does not have the facility to model taps, the transformer could be entered as three branches provided that the program uses a driving voltage and a "ground" or fault bus. The "ground" bus is not the same as the source bus used or "internal voltage" bus used in some programs.

The common configuration is not the best for illustrating the procedure because the fault shorts out one shunt connection of the transformer. A 4.16 kV impedance between the transformer and fault would produce a voltage rise at the secondary of the transformer and some current would flow in that branch.

The transformer tap value is often in per-unit of the transformer rated taps with the expression below.

$$\text{Tap value} = \frac{\text{Tapped winding rated voltage}}{\text{Rated tap voltage}} \quad (3.23)$$

When the transformer voltage ratio does not equal the base voltage ratio and a program with taps representation is used then a fictitious tap value can be used to resolve the difference. The expression is:

$$\text{Fictitious tap value} = \frac{(\text{Tapped winding rated tap voltage})(\text{Untapped winding base voltage})}{(\text{Untapped winding rated voltage})(\text{Tapped winding base voltage})} \quad (3.24)$$

The nameplate transformer impedance requires modification if the untapped winding voltage rating does not equal the base voltage.

In the examination of the sample configurations, it appears that the fault duty on the secondary side is not fixed for a given transformer. For a given transformer, it was noted above that the impedance was taken to be constant over the tap range. Given that statement, the fault duty in MVA on the secondary side should be constant. Comparing Figure 3-1a and Figure 3-24c shows such conditions where the fault current is different. This is best illustrated by comparing the volt-ampere to the fault. Both Figure 3-1a and Figure 3-24c provide the same value.

$$\text{From Figure 3-1a: MVA} = 17.35 \times 4.16 \times \sqrt{3} = 125 \text{ MVA}$$

$$\text{From Figure 3-24h: MVA} = 16.91 \times 4.2667 \times \sqrt{3} = 125 \text{ MVA}$$

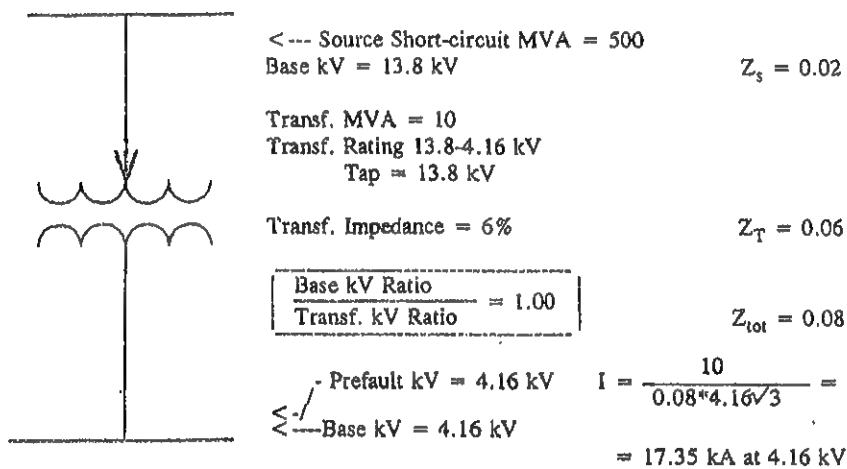
For breakers applied to 4.16 kV systems, the breakers have a constant volt-ampere capability between its minimum and maximum voltage rating. Therefore, the numbers above are being applied at the same percent of maximum breaker capability.

Figure 3-24f and Figure 3-24g have a condition where the transformer tap or high primary voltage would make the secondary prefault voltage high if no load was placed on the transformer. In these cases, it was assumed that the voltage was the result of a power flow calculation and the prefault current flow through the transformer resulted in the bus voltage being one per-unit. Using the no load prefault voltage would result in the fault currents being higher by the ratio of (no load voltage/prefault voltage). Figure 3-24f would equal 17.57 kA and Figure 3-24g would equal 17.85 kA.

In Figure 3-24 the term

$$\frac{\text{Base kV ratio}}{\text{Transf. kV ratio}}$$

is defined as Base kV Ratio = Base kV at transformer primary / Base kV at transformer secondary and Transformer kV ratio = Transformer primary tap kV / Transformer secondary tap kV.



**Figure 3-1a—Transformer kV equals base kV
Transformer rated kV ratio equals base kV ratio**

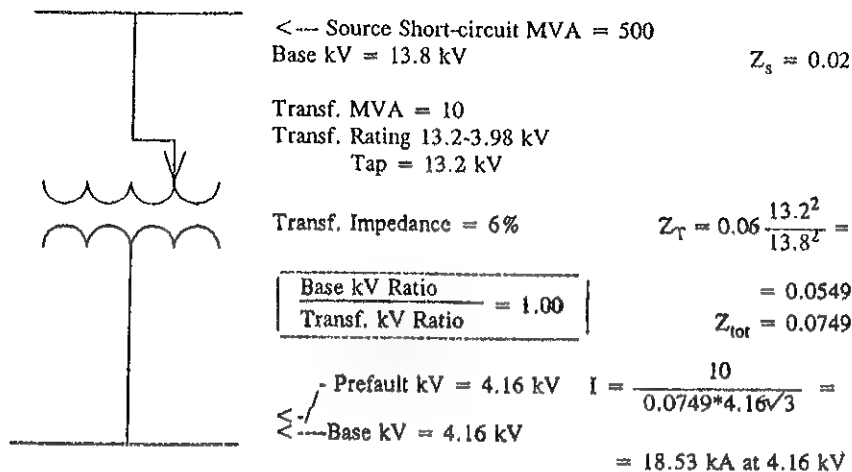


Figure 3-24b—Transformer rated kV not equal to base kV
Transformer rated kV ratio equals base kV ratio

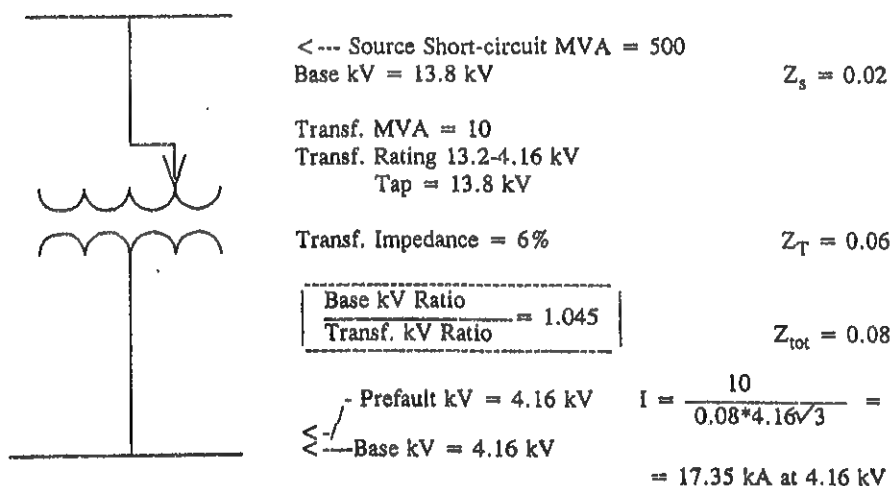
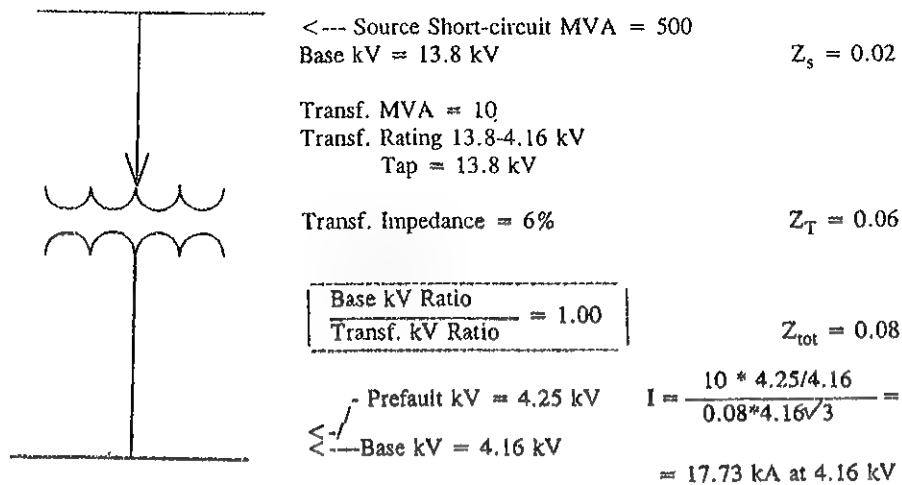
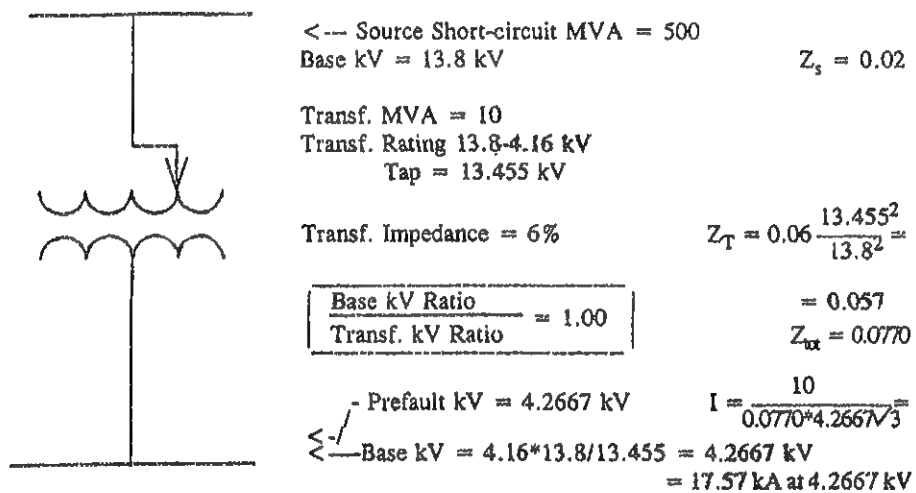


Figure 3-24c—Transformer tapped kV equals to base kV
Transformer rated kV ratio not equal to base kV ratio



**Figure 3-24d—Transformer rated and tapped kV ratio equals base kV ratio
Secondary prefault kV not equal to bus base kV**



**Figure 3-24e—Transformer rated kV equals to base kV
Transformer tapped kV not equal to base kV
Secondary prefault kV not equal to bus base kV**

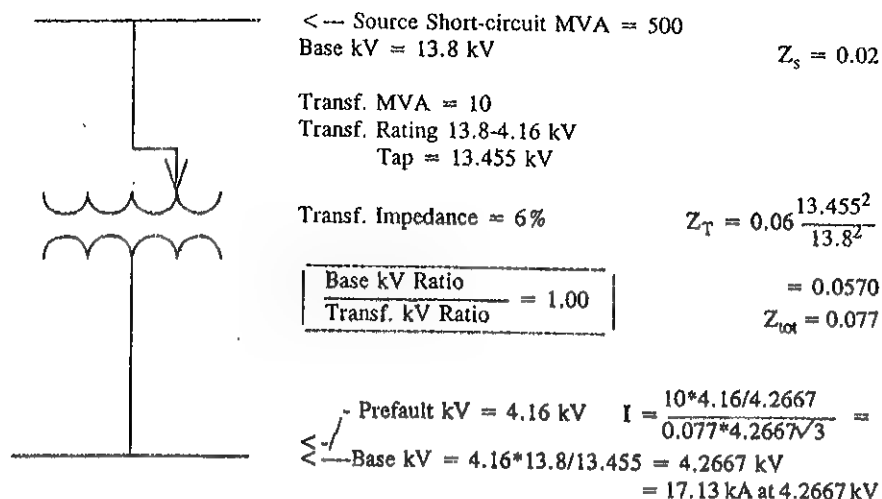


Figure 3-24f—Transformer rated kV equals to base kV
Transformer tapped kV not equal to base kV
Secondary prefault kV equal to bus base kV

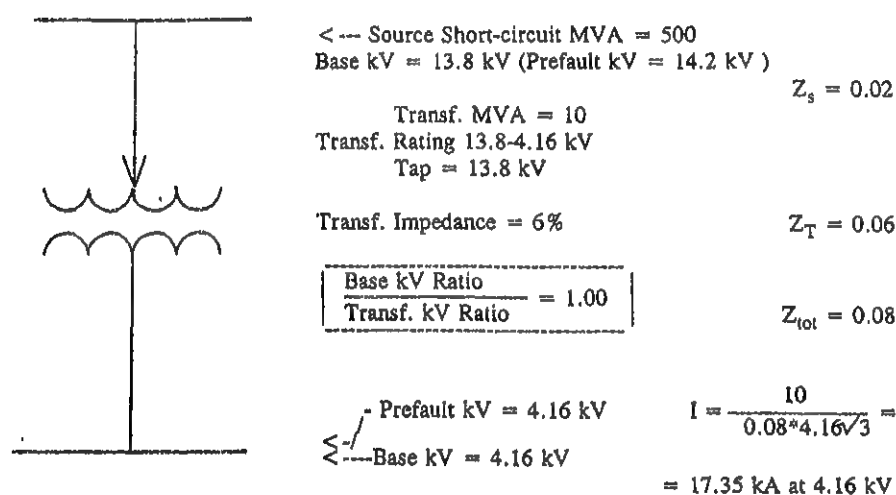


Figure 3-24g—Transformer kV equals base kV
Transformer kV equals base kV ratio
Primary prefault kV not equal to bus base kV

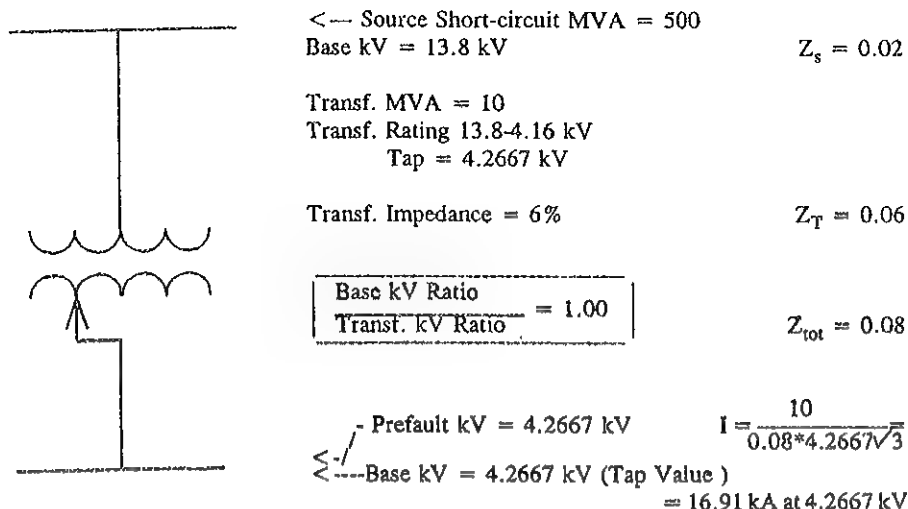


Figure 3-24h—Transformer kV not equal to base kV
Transformer kV ratio equals base kV ratio

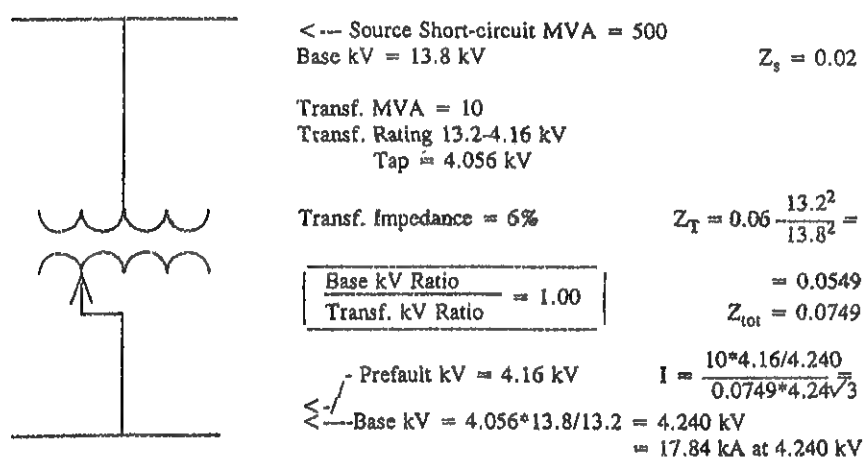


Figure 3-24i—Transformer tap kV not equal to base kV
Transformer rated kV ratio equals base kV ratio
Secondary prefault voltage not equal to base kV

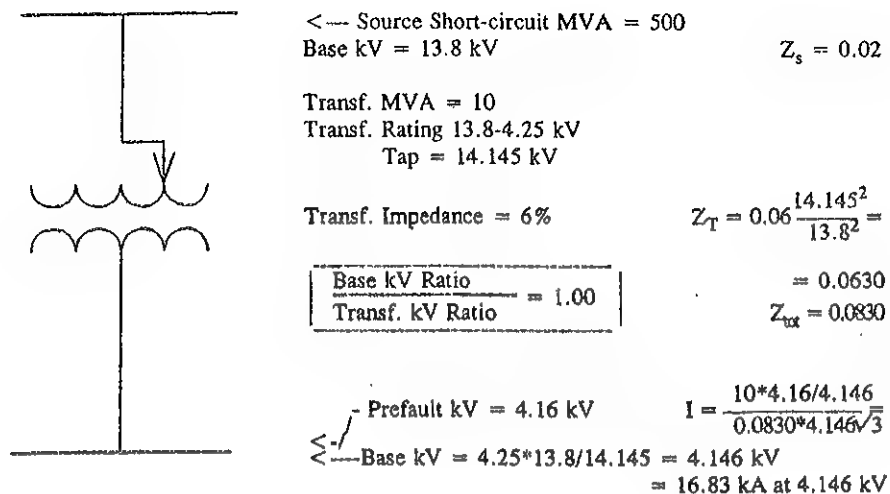
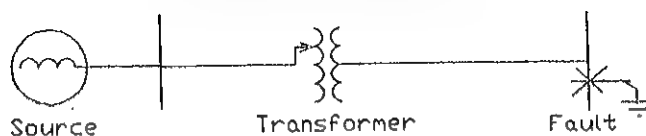


Figure 3-24j—Transformer tap kV not equal to base kV
Transformer kV ratio equals base kV ratio
Secondary prefault voltage not equal to base kV

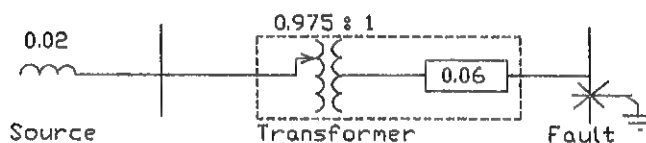
Source Short-circuit
MVA = 500
Base kV = 13.8 kV

Transf. MVA = 10
Transf. Rating Base kV = 4.16
13.8-4.16 kV Prefault kV = 4.16 kV
Tap = 13 455 kV
Impedance = 6%

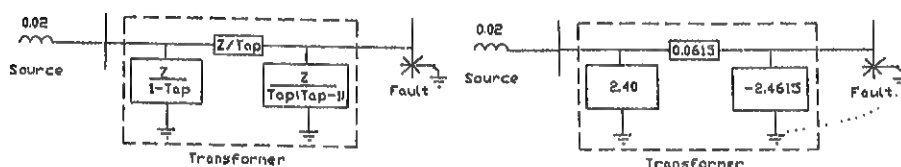
$$\frac{\text{Base kV Ratio}}{\text{Transf. kV Ratio}} = 1.0256$$



Schematic Diagram of Tapped Transformer



Representation of Tapped Transformer



Impedance -2.34 is shorted by fault and is equivalent to zero.
Parallel equivalent of 0.0615 and 2.40 is 0.060 added to the source impedance of 0.02.

$$I = \frac{10}{0.080 \times 4.16 \sqrt{3}} = 17.35 \text{ kA}$$

Figure 3-24k—Transformer tap kV not equal to base kV
Transformer kV ratio not equal to base kV ratio

3.9 Specific time period and variations on fault calculations

Short-circuit calculations used in industrial and commercial power systems have several purposes. One purpose is to establish the maximum calculated available short-circuit duties to be compared with the equipment short-circuit ratings or capabilities. Bolted three-phase short-circuits are normally assumed. First-cycle maximum symmetrical duties are used to compare equipment with first-cycle equipment ratings (momentary or close-and-latch) when rated on a symmetrical current basis, while total (asymmetrical) duties are required for equipment rated on a total current basis. In either case, the X/R ratio of the

fault is also required to calculate the asymmetry of the short-circuit current to ensure that the maximum possible current (ac plus dc) does not exceed equipment ratings. The application of equipment is explained in more detail in Chapter 11. Short-circuit current magnitudes evaluated at times ranging from 1.5 to 4 cycles at 60 Hz are used to determine the interrupting duties for ac medium- and high-voltage circuit breaker applications.

The second purpose is to establish currents useful for protective relaying. Both minimum and maximum currents at the point of fault and as distributed through the system are of interest. Three-phase, line-to-ground, and other types of fault studies may be required. First-cycle maximum short-circuit currents may be used when providing settings for instantaneous or high-speed relays. The currents at longer times after short-circuit initiation are needed for relay settings and also for estimating the performance of time delay relays. Currents calculated at “approximately 30 cycles” are recommended to be used for back-up time delay relays. Often the current values after 30 cycles following the fault initiation are desired for both maximum and minimum generating or operating conditions.

The first-cycle short-circuit currents are also used in determining the magnetic forces that the equipment will be subjected to until the short circuit is cleared. As previously mentioned, these forces are a function of the instantaneous values of current squared.

The maximum value is the crest value of the maximum asymmetric current that the circuit can produce. It is available in the first half cycle after the short circuit occurs. Equipment nameplate data does not provide the magnetic force data directly. Instead, the maximum magnetic forces are indirectly given by the maximum current the equipment can carry.

The total duration of the short circuit determines the thermal energy available to be released in the equipment.

This energy is a function of the amplitude of the current and the time duration.

$$\text{The thermal energy } T_{\square} = R \int i^2 dt \text{ Joules} \quad (3.25)$$

where R is the equipment resistance.

It can be shown that the energy content is a function of the system X/R ratio because the total current (ac plus dc) must be accounted for in the evaluation of the thermal energy produced. Again, equipment nameplate data does not provide the thermal energy and magnetic force data directly, but is encompassed by the equipment maximum current carrying capacity and the time for which this current is allowed to flow.

The equivalent impedance to be used for calculating fault currents at different time periods is shown in the following table. The reactance values are general and may differ between standards. The applicable ANSI-approved standards specify the impedance multipliers that should be applied to the rotating machine impedances in the equivalent circuit. These values are given in IEEE Std C37.010 [B8].

In Table 3-1, depending on the purpose of the calculation, X''_d (modified) may be used with a multiplier in some cases and in other cases X'_d is being used.

Table 3-1—Appropriate reactance values for the different cycles

Equipment	1st cycle currents	3–5 cycle currents	30 cycle currents
Remote sources	X	X	X
Generators	X''_d	$X''_d(\text{modified})$	X'_d^*
Synch. motors	X''_d	$X''_d(\text{modified})$	X'_d or
		$X'_d(\text{modified})^*$	
Induction motors	X''	$X''(\text{modified})$	\times

When the maximum value of short-circuit current 30 cycles after fault initiation is desired, the equivalent circuit (used like a Thevenin equivalent) should include positive sequence impedances yielding toward maximum current magnitudes. In addition, the circuit should include any rotating machines that might still be contributing to the short-circuit fault. This equivalent circuit usually contains generators represented by transient impedance and minimum utility system impedances representing maximum available short-circuit currents.

Induction motors close to the fault will normally either have been disconnected by their undervoltage devices, or the magnetic energy stored in the motor will be completely decayed and hence will not contribute short-circuit currents at 30 cycles.

Depending on the type of excitation system on synchronous generators or motors, 30 cycle short-circuit current decay associated with synchronous machines still connected to the system will vary greatly. Machine excitation systems that rectify the ac bus voltage for field current may decay to near zero during a nearby fault, while other excitation system capable of current forcing could provide 1.5 to 3 times full-load current at 30 cycles. For maximum short-circuit current some engineers include these motors using transient impedances in the equivalent circuit.

Fault durations of 30 cycles or more that are in close proximity to rotating synchronous machines will most likely cause the synchronous machine to pull out of step with the remainder of the system. In such cases, a dynamic model of the system would be required for more accurate results.

It should be noted that the maximum line-to-line or line-to-ground short-circuit current can become greater than the maximum three-phase short-circuit current for a persistent fault because the positive sequence impedance of the equipment is increasing while the negative and zero sequence impedances remain constant. Also, the zero sequence

impedance may be smaller than the positive and negative sequence impedance at the time of fault initiation.

When the minimum value of a 30 cycle bolted three-phase short-circuit current is required in checking relay operation, the equivalent circuit should simulate operating conditions that tend to minimize short-circuit currents, and should include the minimum number of generators connected and the maximum utility source impedance value representing the minimum available short-circuit currents. Generators are generally represented by transient impedances. Induction and synchronous motor contributions are omitted.

3.10 Determination of X/R ratios for ANSI fault calculations

The breaker duty fault point X/R ratio is found from separate X only and R only networks derived from the equivalent circuit as described in 5.3.2 of IEEE Std C37.010 [B8]. There is no completely accurate means of combining two or more parallel circuits with different values of X/R into a single circuit with one value of X/R . The current from individual branches of the parallel circuits and sources behind them will be the sum of several exponentially decaying terms, usually with different decay rates, while the X/R ratio calculated from a single Thevenin equivalent circuit contains just one such term.

For radially-fed circuits, there will be no difference between solving for the fault point X/R ratio using either the X_{only} and R_{only} approach or the (single) Thevenin equivalent approach. (Note that “radially-fed” means that there is only one source of fault current.) However, even the addition of a single motor at the end of a radial feeder with a significantly different machine X/R ratio as compared to the system impedance will cause a different X/R ratio at the fault point between the two calculation methods. It should be noted that an accurate method of determining the fault point X/R ratio would be to solve the system differential equations with the system represented with resistors, inductors, and capacitors. Even small systems would become difficult to solve. However, the method of using separately derived networks results in a calculated X/R ratio that is generally more conservative (larger) than the (single) Thevenin equivalent method. The Thevenin equivalent method cannot ensure a conservative X/R ratio and should not be used for asymmetry current multipliers for breaker duties. However, the use of a Thevenin equivalent should be adequate for relay application.

It should be noted that the resistance network for first-cycle and for interrupting time calculations is varied for machines by the same multipliers as used for the internal reactance. This caution is noted because some X values may have been increased by reactance multiplying factors, and if the corresponding R values are not similarly increased, the X/R ratio and thus the asymmetrical current multiplying factor will be unrealistically high.

3.11 Three-winding transformers

When a three-winding transformer forms part of the system under analysis, Figure 3-24b shows the equivalent circuit and the impedance expressions that are applicable. Note that the equations that make up Equation (3.26) are not the same as the

equations used for delta-star impedance conversions. Furthermore, Equation (3.26) applies only when all impedances are expressed on a common MVA base. This reflects the method used when the impedance tests are performed on the transformer. Once having made a T equivalent, the delta-star conversion can be used for delta impedance representation if desired.

The transformer impedance values are normally stated in percent and generally on the highest kVA winding base. The transformer nameplate will state which base is used for the impedances. Often when solving the conversion equations, one leg of the equivalent circuit will contain a negative impedance. The negative impedance must be retained to obtain the correct solution. However, it can be added to a series positive impedance if a computer program does not allow a negative impedance. Node "D" is an artificial point in the equivalent circuit and has no meaning in system evaluations.

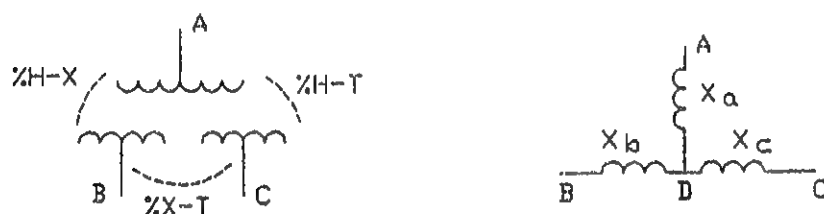


Figure 3-1—Equivalent circuit of a three-winding transformer

$$\begin{aligned} X_a &= 1/2(X_{HX} + X_{HT} - X_{XT}) \\ X_b &= 1/2(X_{XT} + X_{HX} - X_{HT}) \\ X_c &= 1/2(X_{HT} + X_{XT} - X_{HX}) \end{aligned} \quad (3.26)$$

3.12 Duplex reactor

A duplex reactor is a single reactor center tapped, or two reactors physically arranged, so that their magnetic fields are interlinked. With current flowing in one winding only, the reactor behaves the same as a single stand-alone reactor. Simultaneous currents flowing in each winding creates a different situation. The coupling factor, f_c , defines the linking of magnetic fields between the two windings. The flow of current in one winding will induce a voltage in the other winding, (transformer action), which will in turn affect the other winding current flow. A positive coupling factor effectively increases the impedance between nodes "A" and "B," while a negative coupling factor reduces the impedance. A reactor used to reduce fault current magnitudes will have a positive coupling factor. Table 3-2 provides representative coupling factors.

Table 3-2—Representative coupling factors

Circuit voltage (kV)	Coupling factor f_c	
	Indoor or enclosed	Outdoor
0.00–5.0	0.4–0.5	0.3–0.4
5.1–8.7	0.3–0.4	0.2–0.3
8.8–15.0	0.2–0.2	0.2–0.3

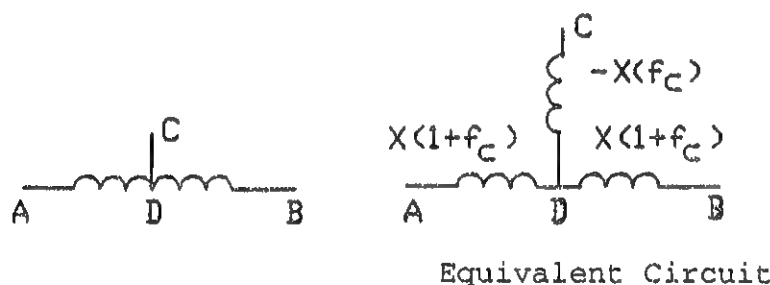


Figure 3-26—Equivalent circuit of a duplex reactor

3.13 Significant cable lengths

Cable impedance can have a significant effect on the short-circuit current in two ways. First, it reduces the magnitude of the symmetrical fault current. Second, because cables generally have low X/R ratios, the cable impedance helps lower the X/R ratio at the fault point. This reduces the total asymmetrical fault current because of a decrease in the dc component. The amount of cable length that should be included in a fault study depends of the system fault level, voltage level, and the accuracy of the results desired. Often cable lengths and configuration of multi-spaced conductors are estimated or neglected. Figure 3-27 provides a guideline of significant cable length if branch current flows will not be reduced by more than 5%. The chart is based on one 350 kcmil conductor per phase. The size of the conductor has a small effect. For conductor sizes ranging from 1/0 AWG to 2000 kcmil the change in significant cable length would be $\pm 15\%$ of that shown in Figure 3-27 for a particular MVA source magnitude. Multiple cables per phase would increase the significant cable lengths by the number of conductors in parallel. Generally, cable lengths to motors are ignored. However, if there is a switching device at the motor, then the cable length may be important if the switch rating is less than the upstream switchgear rating.

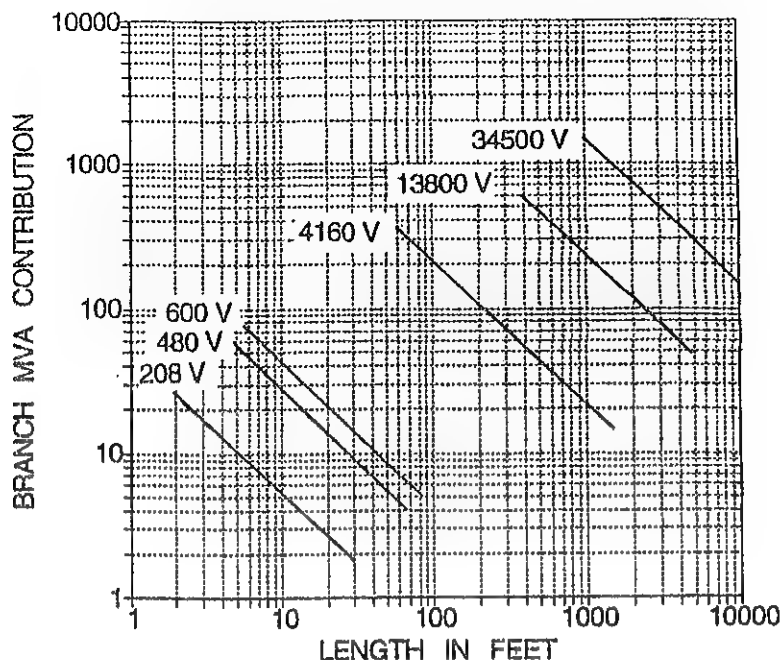
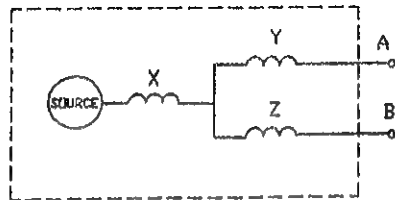
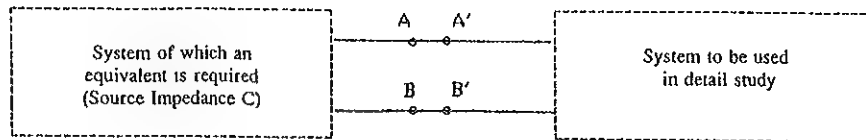


Figure 3-27—Approximate cable lengths for a 5% change in fault current

3.14 Equivalent circuits

It is sometimes desirable to make an equivalent circuit of a larger remotely connected system to reduce unnecessary detail in a portion of a system. These systems could have one or more connections to the system under study. A single tie equivalent can be easily determined by the fault current flow from the remote system and its phase angle. A system with two or more non-independent connections requires more effort. Figure 3-28 shows the steps involved for a three point “T” representation. A “pi” representation could also be used. The procedure is to make an equivalent network and determine an equivalent impedance value. For a two point equivalent, this requires solving for three unknowns by placing three separate faults on the system. The equivalent impedance determined from the equations could have two possible solutions. One answer may involve a negative impedance. While a negative impedance is a mathematically correct solution, it is not generally the answer used. The second solution has a positive impedance and is generally the impedance used.

A three point equivalent requires solving six unknowns. The number of equations to be solved varies by the expression $(\text{points}^2 + \text{points})/2$ and quickly becomes too cumbersome to do by hand. Some computer network analysis programs can perform this function. An alternate method is to work with the network to be reduced and to combine impedances by using series, parallel, and delta-star conversions until the desired nodes remain.



From step 2, $X + Y = \text{Impedance A}$

From step 3, $X + Z = \text{Impedance B}$

From step 4, $X + \frac{Y * Z}{Y + Z} = \text{Impedance C}$

Substituting and solving for X: $X = C \pm (C^2 + A*B - A*C - B*C)^{1/2}$
with Y and Z solved from equations of steps 2 and 3.

- (1) Open circuit at A to A' and B to B'.
- (2) Short circuit node A and determine source impedance A.
- (2a) Restore the open circuit
- (3) Short circuit node B and determine source impedance B.
- (3a) Restore the open circuit
- (4) Join A and B with zero impedance and short common node, C. Determine source impedance C.

Figure 3-28—"T" equivalent circuit

3.15 Zero sequence line representation

When unbalanced fault calculations are required involving cables or transmission lines that are mutually coupled in the zero sequence network, special handling of the circuits is required. Many computer based programs can handle these types of circuits in any line combination. Coupled lines between the same two buses are easily handled by changing the zero sequence impedance when one or two lines are in service. Lines that connect between different buses require a 1:1 ratio mutual-coupling transformer. The condition of the lines being common on one bus is a condition that can be handled by hand or in computer programs without zero sequence mutual coupling. It requires that the two line sections be handled as shown in Figure 3-29 and is similar to the duplex reactor previously shown in Figure 3-26.

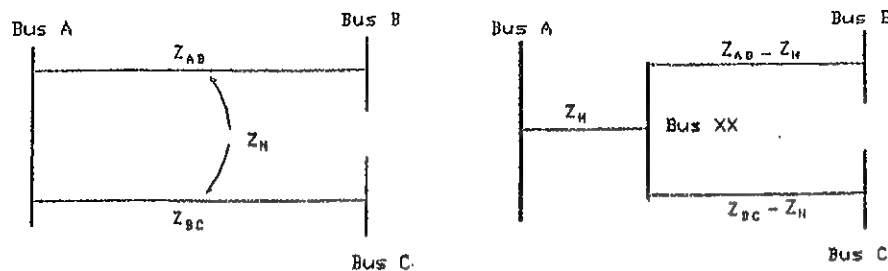


Figure 3-29—Equivalent zero sequence mutual circuit

3.16 Equipment data required for short-circuit calculations

One of the most time consuming and critical items required in a short-circuit analysis is obtaining available data. The less data that is assumed, the better and more accurate the results. There are conditions when most of the data may initially have to be estimated, such as when designing a new system. As the system becomes finalized, specific equipment data may be available and the results are more pertinent. On existing systems, the amount of estimated data is greatly reduced.

An up-to-date one-line diagram is needed. If one is not available, site inspection is required to determine switchgear and load center connection points. There may be cases where no information exists regarding the interconnection of plant loads back to the utility supply. The lack of information is usually the result of a temporary “quick fix” that never properly became documented and over time became permanent. A time consuming tracing of conductors is required to identify its connection to known point. One great value of the short-circuit study is therefore an up-to-date one-line diagram.

In the discussion in 3.16.1, the available data used for short-circuit calculations that can be obtained from equipment nameplates is noted by an *. Other data required will have to be itemized and requested or gathered separately. The data is then converted to ohms or per-unit ohms before it can be used in the analysis.

3.16.1 Utility sources

The equipment impedance data for the utility source must be obtained from the utility company. When requesting the data, specify at what point the source contribution equivalent is to be desired, form desired (per-unit, MVA, or amperes), base voltage used for the calculation, X/R ratio at the point specified, and if data desired is for three-phase or three-phase and line-to-ground calculations. A one-line diagram sketch is often helpful in defining the point of the equivalent. Most utilities do not include the industrial user as a source of short-circuit current unless in-plant generation is present. In addition, the equivalent source impedance will be from a complex $R + jX$ calculation. Generally, the source impedance from neither a separate R and X (R_{only} and X_{only}) nor first-cycle and

interrupting time calculations will be available. When one set of impedances is furnished by the utility, it is generally assumed to be the maximum short-circuit value or the first-cycle value. If the plant has more than one connection point, then a more complex equivalent is required and part of the utility may have to be represented. See 4.3 for more detail. Typical forms of the data received from the utility is given below:

- 1) MVA with phase angle or X/R ratio. (Requires voltage level at which MVA was calculated.)
- 2) Fault current with phase angle or X/R ratio. (Requires voltage level at which current is calculated.)
- 3) Resistance and reactance in ohms. (Requires voltage level at which ohms are calculated.)
- 4) Per-unit resistance and reactance. (Requires voltage level and MVA base, usually 100 MVA).
- 5) Percent resistance and reactance. (Requires voltage level and MVA base, usually 100 MVA).

3.16.2 Generators

The data available from the machine nameplate is not significantly complete for an accurate short-circuit calculation. Typical data on the nameplate is as follows:

- a) Manufacturer and serial number
- b) Rated MVA* and voltage*
- c) Rated frequency and machine speed
- d) Rated current and field voltage

The machine nameplate data required for short-circuit calculations is noted by an *. While some of the above data is useful, the machine impedances, if furnished, are supplied on a separate data sheet. If this data sheet is not available, the manufacturer can usually provide the data required if the serial number is available. This data may have to be recalculated or extracted from the original drawings at a cost to the user. On machines built in the early 1900s, the subtransient impedance was defined differently from what it is today. A recalculation by the vendor could result in different impedance values as compared to what was originally furnished. The following data is required for short-circuit calculations:

- 1) X''_{dv} – rated voltage (saturated) direct-axis subtransient reactance (first-cycle and interrupting calculations)
- 2) X'_{dv} – rated voltage (saturated) direct-axis transient reactance (relaying time calculations)
- 3) X_{2V} – rated-voltage (saturated) negative sequence reactance (used to calculate X/R ratio, and in unbalanced fault calculations)
- 4) T_{A3} – rated-voltage generator armature time constant in seconds, or R_a – armature resistance, (used to calculate X/R ratio)
- 5) Short-circuit current decrement curve (not required, but will be useful in relaying time calculations)

- 6) X_0 – zero sequence reactance (used in unbalanced fault calculations for grounded generators)

One item not supplied as part of the generator nameplate or data sheet that may be required for relaying time calculations is the type of voltage regulator used with the generator. See 3.9 for the effects of regulators on extended time fault calculations.

3.16.3 Synchronous motors

The data required for synchronous motors is the same as that furnished for generators. Machine nameplate data may not be sufficiently complete for an accurate short-circuit analysis. Typical data on the nameplate is as follows:

- a) Manufacturer and serial number
- b) Rated MVA* and voltage*
- c) Rated frequency and machine speed
- d) Rated current and field voltage

The machine nameplate data required for short-circuit calculations is noted by an *. While some of the above data is useful, the machine impedances, if available, are given on a separate data sheet. If a data sheet is not available, the manufacturer can usually provide the data required if the serial number is available. This data may have to be recalculated or extracted from the original drawings at a cost to the user. Some manufacturers may only furnish one transient or subtransient impedance for motors, which is usually the rated voltage X''_{dv} value that is desired for short-circuit calculations. The following data is required for short-circuit calculations:

- 1) X''_{dv} – rated voltage (saturated) direct-axis subtransient reactance (first-cycle and interrupting calculations)
- 2) X'_{dv} – rated voltage (saturated) direct-axis transient reactance (relaying time calculations)
- 3) X_{2V} – rated-voltage (saturated) negative sequence reactance (used to calculate X/R ratio and unbalanced faults)
- 4) T_{A3} – rated-voltage generator armature time constant in seconds, or R_a – armature resistance, (used to calculate X/R ratio)
- 5) Short-circuit current decrement curve (not required, but may be useful in relaying time calculations)
- 6) X_0 – zero sequence reactance (used in unbalanced fault calculations for grounded motors. Most wye connected motors are not connected to system neutrals)

One item not supplied as part of the motor nameplate or data sheet that may be required for relaying time calculations is the type of voltage regulator used with the motor. Most of the present day regulators are of the potential source type and do not supply sustained short-circuit currents. See 3.9 for the effects of regulators on extended time fault calculations.

3.16.4 Induction motors

Some data required for short-circuit studies that include induction motors is on the motor nameplate. But the nameplate data is not sufficiently complete for an accurate short-circuit calculations. Typical data on the nameplate is as follows:

- a) Manufacturer and serial number
- b) Rated HP or MVA* and voltage*
- c) Rated frequency and motor speed*
- d) Rated current and NEMA code letter*

Data required for short-circuit calculations is noted by an *. Machine impedances are seldom furnished on a separate data sheet. However, if a data sheet is available, the manufacturer usually specifies the locked-rotor current that can be used to estimate the motor subtransient impedance. More detailed impedance data is available at a cost, but is usually not justified. Different impedance data is furnished for the motor at both stall and running conditions and the resistances furnished may not include the one required for short-circuit calculations. The motor starting reactance is most often used for short-circuit calculation. However, the resistance to be used for short-circuit calculations is lower than the starting resistance provided on the data sheet. Unless a short-circuit resistance is provided, typical motor X/R ratio curves can be used.

Data for smaller motors is usually estimated because the cost of obtaining this information is not justified.

3.16.5 Transformers

Transformer nameplates usually provide most of the data required for short-circuit calculations. Typical data on the nameplate is as follows:

- 1) Manufacturer and serial number
- 2) Rated MVA* and frequency
- 3) Rated primary and secondary voltages*
- 4) Rated current and taps available*
- 5) Transformer percent impedance*
- 6) Number of windings, winding connection and phase relationship* (needed for unbalanced fault calculations)
- 7) Manufacturer test report.

The nameplate data required for short-circuit calculations is noted by an *. Note that the transformer nameplate data is given as a percent impedance and not percent reactance and is generally given on the self cooled rating unless otherwise specified. The reactance is determined once the percent resistance is known. The transformer X/R ratio is not on the nameplate, but can be determined from the transformer test sheet or losses, if provided. Some data sheets do provide the % resistance as a piece of data; otherwise, the % resistance is determined by:

$$\%R = \frac{(Total\ watt\ loss - no\ load\ loss)100}{Transformer\ rating\ in\ volt\ amperes}$$

or

$$\%R = \frac{(Full\ load\ winding\ loss)100}{Transformer\ rating\ in\ volt\ amperes}$$

The standard phase relationship of a delta-wye or wye-delta transformer is that the high-voltage side leads the low-voltage side by 30 degrees for positive phase sequence systems. When performing unbalanced fault calculations, the positive sequence current and voltage shifts by either +30 degrees or -30 degrees, while the negative sequence current and voltage have the same phase shift but in the opposite direction. Note that one side of the transformer is selected as reference. With the reference established, the phase shift is applied following the general rule of "HV side leads LV side for positive sequence, and HV lags LV for negative sequence." As an example, suppose that a delta-wye transformer has the HV winding selected as reference. Based on this choice of reference, the positive sequence LV side values will lag the positive sequence HV side values, and the negative sequence LV side values will lead the negative sequence HV side values. The signs on the phase shifts would be exactly reversed if the LV side were selected as reference and the HV side values were required to be shifted with respect to the LV side values. There will be no shift of the zero sequence current since there is no path for this current component to flow. The zero sequence voltage is determined by the zero sequence impedance times the zero sequence current flow on each side of the transformer.

3.16.6 Reactors

The reactor nameplate usually provides most of the data required for short-circuit calculations. Typical data on the nameplate is:

- 1) Manufacturer and serial number
- 2) Rated voltage* and frequency
- 3) Rated current* and taps available*
- 4) Reactor percent impedance*
- 5) Reactor ohms* (not always provided)
- 6) Percent voltage drop* (not always provided)
- 7) Manufacturer test report

The nameplate data required for short-circuit calculations is noted by an *. The reactor X/R ratio is not on the nameplate, but can be determined from the reactor test sheet or losses, if provided. Some data sheets do provide the reactance, the resistance, and reactor "Q" factor as a piece of data. Not all the above * items can be used directly for a short-circuit calculation. For example, the percent impedance is on the "through" kVA (volts \times amps) of the reactor and for a three-phase reactor the through kVA is:

$$\text{Through kVA} = \sqrt{3} I_{\text{Rated}} V_{\text{Rated, LL}}$$

The impedance can also be determined from the voltage drop as follows:

$$\text{Impedance in ohms} = \text{volt drop in volts} / I_{\text{Rated}}$$

The base for the percent voltage drop (when used) is line-to-line rated voltage.

For a three-phase reactor, the “self” kVA is as follows:

$$\text{Self kVA} = 3 I_{\text{Rated}}^2 X$$

3.16.7 Capacitors

The inclusion of capacitor data is usually not necessary under most conditions. See the chapter on capacitor contributions to short-circuit currents to determine the actual extent to which capacitors will affect the first-cycle calculations. If inclusion of the capacitor data is required, the capacitors nameplate is complete for short-circuit calculations. The data on the nameplate will be as follows:

- 1) Manufacturer and serial number
- 2) Rated voltage* and frequency
- 3) Rated kvar*

The nameplate data required for short-circuit calculations is noted by an *. The capacitor X/R ratio is not on the nameplate, but is generally very high and can be determined from the capacitor loss test sheet, if it is provided. If assuming the X/R ratio, a value from 200 to 300 should be acceptable, because the series cable resistance quickly overwhelms the capacitor resistance. The length of cable to the capacitor bank is important and should be included.

3.16.8 Static regenerative drives

The inclusion of static regenerative drive data will be necessary in the first-cycle calculations. (Note that non-regenerative drives are not sources of fault current and need not be considered.) The rectifier transformer and drive motor size is required. Typical data on the drive transformer nameplate is as follows:

- 1) Manufacturer and serial number
- 2) Rated voltage* and frequency
- 3) Rated primary and secondary voltages*
- 4) Rated current and taps available*
- 5) Transformer percent impedance*
- 6) Number of windings, winding connection and phase relationship

The nameplate data required for short-circuit calculations is noted by an *. The drive transformer X/R ratio is not on the nameplate, but can be determined from the transformer test sheet or losses, if provided. Some data sheets do provide the percent resistance as a piece of data; otherwise, the percent resistance is determined by:

$$\%R = \frac{(Total\ watt\ loss - no\ load\ loss)100}{Transformer\ rating\ in\ volt\ amperes}$$

or

$$\%R = \frac{(Full\ load\ winding\ loss)100}{Transformer\ rating\ in\ volt\ amperes}$$

Note that the drive transformer nameplate data is given as a percent impedance and not percent reactance. The reactance is determined once the percent resistance is known.

The size of the driven motor load is also required to determine the short-circuit current contribution or equivalent source impedance. The motor size may have to be extracted from drawings. The motor data needed is the same as given for motors in 3.16.3 and 3.16.4. For short-circuit calculations where the drive is modeled as an induction motor, the equivalent drive impedance should be greater than the typical impedance of an induction motor with the same rating.

3.16.9 Breakers, contactors, and current transformers

The inclusion of breaker, contactor, or current transformer impedances is seldom done in short-circuit calculations. These impedances are more significant in low-voltage system analysis than for the higher-voltage systems. The impedances of series connected trip or thermal overload devices in the power circuit on low-voltage systems can greatly reduce the available fault current downstream from such devices and therefore should be included when required. For fractional horsepower motor loads, the thermal overload devices will have an impedance magnitude in ohms as compared to cable impedances in milliohms.

3.16.10 Cables

The connecting cables will not have any impedance data stamped on them. Data typically found on the cable includes the following:

- a) Manufacturer
- b) Rated voltage*
- c) Type of cable* and insulation type*
- d) Size of conductor*

In addition, the following data is required:

- 1) Length
- 2) Type of cable construction (1/C or 3/C)
- 3) Number of cables in parallel and physical spacing
- 4) Type of cable duct used (steel, fiber, cable tray, direct burial, etc.)

Data shown on cable and required for short-circuit calculations is noted by an *. The impedance data per unit of length must be determined from other sources such as

manufacturer's literature or general cable impedances in texts. The cable manufactures literature is preferred, because insulation thickness may differ between manufacturers where as most references provide typical impedance values (see IEEE Std 141-1993 [B6], IEEE Std 242-2001 [B7], Beeman [B1], Stevenson [B10]). References usually provide positive sequence impedance, which is used in three-phase faults. For unbalanced faults, the zero sequence cable data is required and not usually provided in references.

The zero sequence impedances of cables differ from that of the positive and negative sequence and is dependent upon the physical configuration and the impedances of the ground return paths. Formulas for calculating cable impedances are available in many books such as *Elements of Power System Analysis* [B10].

3.16.11 Transmission lines

The impedance data for connecting transmission lines should be based on the line configuration. Drawings or sketches showing wire size, type of conductor material, and conductor spacing are required. In addition, circuit length, type and size of ground wire, and earth resistance must be obtained.

The impedance data per unit of line length will have to determined from other sources such as *Elements of Power System Analysis* [B10] or the *Transmission and Distribution Reference Book* [B13].

3.17 Bibliography

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- [B13] Westinghouse, *Transmission and Distribution Reference Book*.

⁶IEEE publications are available from the Institute of Electrical and Electronics Engineers, 445 Hoes Lane, P.O. Box 1331, Piscataway, NJ 08855-1331, USA (<http://standards.ieee.org/>).

⁷The IEEE standards or products referred to in this subclause are trademarks of the Institute of Electrical and Electronics Engineers, Inc.

Chapter 4

Calculating short-circuit currents for systems without ac delay

4.1 Introduction

This chapter describes the calculation of three-phase short-circuit currents for systems without ac decay [i.e., No AC Decay (NACD)]. The procedures described here are appropriate for equipment sizing evaluations when generation is not located in the immediate electrical area where the calculations for equipment applications are being performed. (Note that procedures in other chapters are appropriate for calculations when generation is present in the local electrical area.) IEEE Std C37.010™-1999 [B3]¹ identifies power system generation, regardless if it is utility or local (plant) generation, as either “local” or “remote” to the fault location. A generator is considered electrically remote if the ratio of the network reactance from the generator terminals to the faults point is $\geq 1.5X_d$. Alternatively a remote generator may be defined as being more than one transformation away from the fault point. Remote generation will not exhibit ac decay characteristics. From the correlation between “remote” and “no ac decay,” it can be implied that a system “with no ac decay” does not have any fault current contribution from nearby rotating equipment. This could be applicable to some subtransmission systems serving residential loads or an industrial plant on a weekend where all the rotating equipment is disconnected. Without any ac decay current, the first cycle and interrupting time calculations use the same impedance network and therefore the symmetrical currents are the same.

This chapter is limited to the consideration of short-circuit currents that occur under the following conditions:

- 1) Short-circuit fault currents that occur in low-voltage ac systems and medium-voltage ac systems operating at a constant frequency and electrically remote from any generators.
- 2) For the duration of the short circuit, there is no change in the source driving voltage or voltages that caused the initial short-circuit current to flow. In addition, system impedances remain constant.
- 3) The fault impedance is zero and has no current limiting effect.
- 4) Motor fault current contribution is negligible.
- 5) For simplification, only three-phase faults will be considered. Unbalanced faults are covered in Chapter 11.

4.2 Purpose

The object of this chapter is to give recommended standardized procedures for the calculation of short-circuit current in systems with NACD. The application and selection

¹The numbers in brackets correspond to those of the bibliography in 4.8.

of interrupting equipment based on the calculated fault currents are covered in Chapter 10. No ac decay calculations are the simplest of the fault calculations and will serve as the basis for the more complex fault current calculations. Fault currents with ac decay are covered in Chapter 5 and Chapter 6. A sample one-line diagram will be used to show the method of calculation and will increase in detail as motors and generators are added in the later chapters. Hand calculations will be made at several locations and computer-generated results will be given for selected other buses. The one-line diagram used is similar to the diagram in the IEEE Std 399™-1997 (*IEEE Brown Book*) [B2].

4.3 ANSI guidelines

The calculation procedure to be used will be based on IEEE Std C37.010 [B3]. An understanding of the analytical techniques of the ANSI method should help in interpreting other calculating procedures such as IEC 909:1977 [B1].

IEEE Std C37.010 [B3] includes three other system conditions, as given in Chapter 3 (3.2), to be used when calculating fault currents. These are as follows:

- 1) The pre-fault bus voltage is 1.0 p.u.
- 2) Separate resistance and reactance networks are to be used to determine the fault point X/R ratio. This X_{sep}/R_{sep} ratio is to be used to calculate the total asymmetrical fault current. As an alternative, Z/R_{sep} can be considered the same as X_{sep}/R_{sep} .
- 3) Load currents are much smaller than the fault current and are therefore neglected.

In IEEE Std C37.010 [B3], several simplified methods are listed for use where the current determined by an E/X calculation (instead of E/Z) meets specific fault current or X/R ratio criteria. For example, when the fault current is less than 80% of the breaker duty, an E/X calculation can be used. To determine if the current calculated by the simplified methods meets these criteria, most of the effort that is needed for the detailed ANSI calculation is already done. Because having several methods to calculate breaker duty current could lead to confusion, the detailed ANSI calculation will be used here. Most computer programs that follow the ANSI recommended method use the more detailed ANSI procedure.

In this chapter, the symmetrical ac component of the short-circuit current has a constant rms magnitude for the duration of the fault. Thus, the rms magnitude of the ac component of current for the system considered is independent of time and will have a constant value determined by the system's highest pre-fault voltage and equivalent series impedance. In Chapter 2, asymmetry was discussed and was shown to depend on the fault point X/R ratio and on the point on the voltage wave at which the fault is initiated. A fault current flowing from a remote source may be asymmetrical and have both an ac and a dc component. The dc component is a transient and decays with time, while the ac component is a constant-amplitude sinusoid. In Chapter 2, several different theoretical and empirical equations were given that relate the maximum peak and rms currents in the first cycle to the ac symmetrical current. For the sample calculations in this chapter, the "Violet Book" equations will be used and are repeated below.

The first cycle Violet Book equations are as follows in Equation (4.1) and Equation (4.2):

$$I_{peak} = I_{ac\ peak} \left(1 + e^{-\frac{2\pi\tau}{(X/R)}} \right) = \sqrt{2} I_{ac\ rms} \left(1 + e^{-\frac{2\pi\tau}{(X/R)}} \right) \quad (4.1)$$

$$I_{rms} = \sqrt{I_{ac\ rms}^2 + I_{dc}^2} = I_{ac\ rms} \sqrt{1 + 2e^{-\frac{4\pi\tau}{(X/R)}}} \quad (4.2)$$

where $\tau = 0.49 - 0.1e^{-\frac{(X/R)}{3}}$

Equation (4.2) can be rewritten to calculate the total rms current at other points in time as shown in Equation (4.3).

$$I_{rms} = I_{ac\ rms} \sqrt{1 + 2e^{-\frac{4\pi\tau}{(X/R)}}} \quad (4.3)$$

where τ is in cycles at 60 Hz.

Equation (4.1) and Equation (4.2) can be used to calculate the maximum asymmetry during the first cycle, while Equation (4.3) can be used for times greater than 1 cycle.

Peak currents are often associated with equipment rated less than 1000 V; rms currents are used with higher-voltage equipment. See the tables in Chapter 2 for the comparisons of the approximation equation peaks with the actual peaks. When equipment operating times are given in cycles at a particular frequency, the time can be ratioed to 60 Hz. For example, five cycles at 50 Hz is the same time as six cycles at 60 Hz.

The dc current decrement for a simple single circuit of one branch is an exponential decay. In a multi-branch power system, a single X/R ratio is only an approximation. Each branch will actually have its own time constant and the total current will decay at some rate that is dependent on the combined effect. There is no single time constant that will exactly describe the dc decrement of a multi-branch total fault current.

For the purpose of simplicity and conservatism, ANSI has recommended that the following simplified procedure be used to determine the X/R ratio for a particular fault. The system impedance diagram is converted to a separate resistance (R) diagram and a separate reactance (X) diagram. The resistance and reactance diagrams are then reduced to a simple resistance (R) and a reactance (X) value at the fault point. These values are then used to determine the system X/R at the fault point. The X/R value in turn determines the system dc time constant and consequently the rate of decay of the transient dc fault current.

4.4 Fault calculations

ANSI fault calculations can be done in per-unit or in ohms with transformer ratios taken into account. The samples used in this book will be shown using the per-unit method. The steps in calculating ANSI fault currents are as follows:

- 1) Obtain an up-to-date one-line diagram.
- 2) Determine the impedance of each branch and source for the time period of concern.
- 3) Reduce the network impedances to single R_{sep} and X_{sep} values using separate R and X network reductions.
- 4) Calculate the fault current by combining the separate R and X values from step 3) into a complex impedance at the fault point or by using the optional complex impedance network impedance determined in step 4).
- 5) Calculate the fault point X/R ratio using X_{sep}/R_{sep} [step 3)] or, alternatively, Z/R_{sep} [step 4)].
- 6) Calculate any asymmetrical currents using results of step 5) and step 6).
- 7) Calculate the branch contributions, if required.
- 8) *Optional:* Reduce the network impedances to a single R_{sep} value using a separate R network reduction. Reduce the network impedances to a single complex impedance using complex network reductions.

4.5 Sample calculations

4.5.1 Sample calculation #1

The complete sample one-line diagram that will be used is given elsewhere in this book. It includes motors and generators that will be included in calculations in the following chapters. In this chapter the utility is the only short-circuit source. A reduced one-line diagram is shown in Figure 4-1.

For a fault on 2.4 kV bus 36:T13 SEC, the total impedance to the fault is the addition of the series impedances to the fault point. This is a special case because the total impedance is not affected by any parallel feeder ties between MILL-1 and MILL-2 buses. Closing either the 480 V breaker on cable C-T12-1 or the 13.8 kV switch on cable C-J5 would require the paralleling of transformers T-1 and T-2 with some cable impedances. This would reduce the effective impedance between the utility and MILL-2 bus and increase the fault level at bus 36:T13 SEC. The equipment raw data and per-unit data are given in Table 4-1. The manual calculations and a typical computer printout are provided on the pages that follow.

Table 4-1—Per-unit impedances of branches

Branch	Per-unit R	Per-unit X
UTIL	0.00045	0.00999
T-line	0.00139	0.00296

Table 4-1—Per-unit impedances of branches (continued)

Branch	Per-unit R	Per-unit X
Transf T-2	0.00313	0.05324
Cable C-M1	0.00118	0.00098
Cable C-M2	0.00079	0.00065
Transf T-13	0.02289	0.22886
Sum	0.02983	0.29668

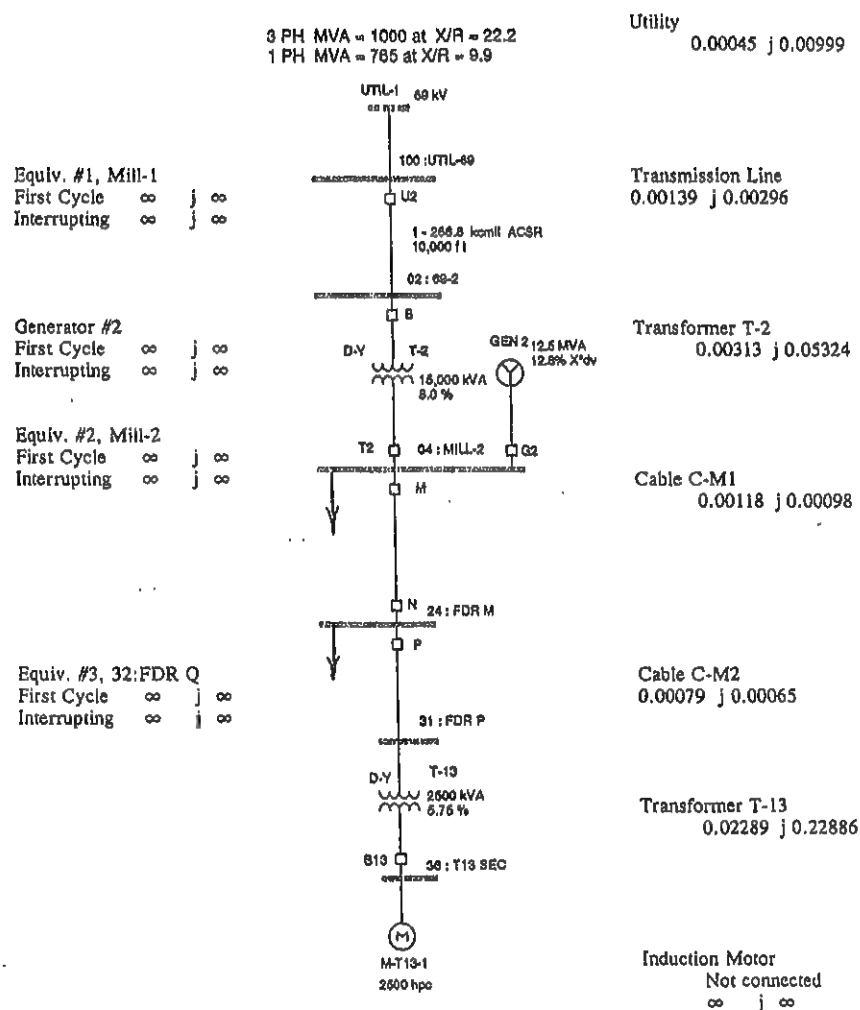


Figure 4-1—Equivalents and impedance one-line diagram for sample calculations

The per-unit (p.u.) current with 1.00 p.u. source voltage is as follows:

$$I_{pu} = \frac{E}{Z} = \frac{1.0}{0.02983 + j0.29668} = \frac{1.0}{0.29818} = 3.354 \text{ pu at } -84.258^\circ$$

The fault current is as follows:

$$I = \frac{I_{pu} \times MVA_{base}}{\sqrt{3} \text{ kV}} = \frac{3.354 \times 10}{100 \times \sqrt{3} \times 2.4} = 8.0685 \text{ kA at } -84.258^\circ$$

The fault point X/R ratio is as follows:

$$\frac{X}{R} = \frac{0.29668}{0.02983} = 9.9457$$

For a fault on bus 36:T13 SEC with the 13.8 kV bus tie open, the fault point X/R ratio by separate R and X and complex impedance reduction is the same as the value shown above because there were not any parallel circuits.

The maximum asymmetrical rms current in the first cycle is, from Equation (2.3),

$$\tau = 0.49 - 0.1e^{\frac{(X/R)}{3}} = 0.4864$$

$$I_{rms} = I_{ac \text{ rms}} \sqrt{1 + 2e^{\frac{4\pi\tau}{(X/R)}}} = 8.0685(1.4228) = 11.642 \text{ kA}$$

A sample computer printout for bus 36:T13 SEC is shown below.

```
* BUS: 36:T13 SEC *****
  8.068 KA AT -84.26 DEG ( 33.54 MVA): X/R = 9.95 KV = 2.400
Ze = 0.0298306 +j 0.2966802 (Complex)
SYM kA*1.6 = 12.91      ASYM kA Based on X/R ratio = 11.64 kA

CONTRIBUTIONS TO FAULT:
BUS to BUS      MAG      ANG
31:FDR P 36:T13 SE 8.068    -84.26
```

As an option, the symmetrical fault current could have been calculated using only the reactance (0.29668). The fault symmetrical current would be 8.109 kA for a slightly more conservative answer.

4.5.2 Sample calculation #2

Closing the 13.8 kV bus tie would increase the fault level and would also result in a parallel circuit, which results in the fault point X/R ratio by separate R and X and the

complex impedance reduction being different. First, paralleling the two transmission lines and main transformers results in the impedances shown in Table 4-2.

Separate R and X paralleling of the transmission lines and transformers gives $R = 0.002136$ and $X = 0.028075$. The complex paralleling of the same two branches would result in $0.002142 + j 0.028075$, which has a slightly higher resistance. Table 4-3 shows the impedance results for the separate R and X values all the way to the fault point.

Table 4-2—Parallel equivalent of T-lines and transformers

	T-line and transf T1		T-line and transf T2	
	P.U. R	P.U. X	P.U. R	P.U. X
	0.00139	0.00296	0.00139	0.00296
	0.00266	0.05324	0.00313	0.05324
Sum	0.00405	0.05620	0.00452	0.05620

Table 4-3—Separate R and X equivalents of T-lines and transformers

Branch	P.U. R	P.U. X
UTIL	0.00045	0.00999
T-Line and transf T1 in parallel with T-line and transf T2		
(from above)	0.002136	0.02808
Cable C-M1	0.00118	0.00098
Cable C-M2	0.00079	0.00065
Transf T-13	0.02289	0.22886
Sum (separate R and X)	0.027446	0.26856

Using the complex math paralleling, the sum would be $0.027452 + j0.268025$ instead of 0.027446 and $j0.26803$ as shown by separate R and X reductions.

The per-unit fault current using separate R and X would be as follows:

$$I_{pu} = \frac{E}{Z} = \frac{1.0}{0.027446 + j0.26856} = \frac{1.0}{0.27996} = 3.7043 \text{ pu at } -84.165^\circ$$

The fault current is:

$$I = \frac{I_{pu} \times MVA_{base}}{\sqrt{3} kV} = \frac{3.7043 \times 10}{1000 \times \sqrt{3} \times 2.4} = 8.9111 \text{ kA at } -84.165^\circ$$

$$\frac{X}{R} = \frac{0.26856}{0.027446} = 9.785$$

As an option, to calculate the fault current, the complex impedance to the fault point can be used. The fault current using the complex network reduction to four decimal places is 8.9111 kA at -84.165° . The fault point X/R ratio is calculated from the separate R and X network reductions to be 9.7655. For this example, the current magnitude and its angle by either network reduction are nearly the same. However, there can be cases where the current and X/R ratio difference is greater. This occurs when parallel branches that have wide differences in X/R ratios are present in the system.

4.5.3 Sample calculation #3

In this example, transformer T13 is changed and has a rating of 2.5 MVA, 13.2/2.3 kV, 5.75% impedance, and the selected operating tap is 13.53 kV. Because the transformer voltage rating does not match the 13.8 kV base voltage, two items should be changed, one is the transformer impedance and the other is a base voltage. To correct the impedance to the primary 13.8 kV voltage base, Equation (3.12) from Chapter 3 is used.

$$Z_{Common\ base} = Z_{Equipment} \frac{kV_{Equipment\ base}^2}{kV_{Common\ base}^2}$$

$$Z_{Common\ base} = (5.75) \frac{13.2^2}{13.8^2} = 5.261\%$$

The original 5.75% Z or the modified 5.261% Z can be entered into some computer programs with the 13.53 kV tap and the transformer impedance will be corrected for tap position. However, for hand calculations or computer programs without transformer tap capabilities, a second step is required to correct for the transformer tap position. The same equation as shown above can be used to calculate the change in transformer percent impedance in one step. Two steps are shown for clarity.

$$Z_{Common\ base} = (5.261) \frac{13.53^2}{13.2^2} = 5.5273\%$$

Using an X/R ratio of 10, the transformer T13 per-unit impedance on the 10 MVA (13.53 kV) system base is as follows:

$$0.02200 + j0.21999$$

The secondary system base voltage is $2.3 \times 13.53/13.2 = 2.3575$ kV.

Table 4.4 shows the branch impedance values for this example.

Table 4.4—Per-unit impedance values of branches

Branch	P.U. R	P.U. X
UTIL	0.00045	0.00999
T-line	0.00139	0.00286
Transf T-2	0.00313	0.05324
Cable C-M1	0.00118	0.00098
Cable C-M2	0.00079	0.00065
Transf T-13	0.02200	0.21999
Sum	0.02894	0.28771

The per-unit current with 1.00 p.u. source voltage is as follows:

$$I_{pu} = \frac{E}{Z} = \frac{1.0}{0.02894 + j0.28771} = \frac{1.0}{0.28916} = 3.4583 \text{ pu at } -84.256^\circ$$

The fault current is as follows:

$$I = \frac{I_{pu} \times \text{MVA}_{\text{base}}}{\sqrt{3} \text{ kV}} = \frac{3.47037 \times 10}{1000 \times \sqrt{3} \times 2.3575} = 8.3193 \text{ kA at } -84.256^\circ$$

The fault point X/R ratio is as follows:

$$\frac{X}{R} = \frac{0.28771}{0.02894} = 9.942$$

4.6 Sample computer printout

The following is a summary of a computer printout for Sample Calculation #1. The printout is shown in three sections. The first section provides the raw data listing. This raw data list provides just the more generic data required for data conversion into per-unit on common bases.

The second section of the printout contains the per-unit data that was used in the actual short-circuit calculations. The impedance listing summarizes the bus-to-bus and bus-to-source interconnections as shown on the one-line diagram. The sequence of entering the

data is arbitrary although sources of short-circuit current (utility connections, generators, or motors) are noted as connected to bus 0 (zero). The calculated per-unit impedance data listing is on a 10 MVA, 60 Hz base. Not all computer programs will provide the same per-unit data for the equipment given. For example, the generator X/R ratio could either be a manual input or assigned within the program using typical data. Cable impedances depend upon the assigned operating temperature of the cable, type and thickness of insulation, and the type of raceway or conduit used and other assumptions made. Different engineers will use different assumptions when exact data is not available and therefore a different cable impedance may be obtained.

The third section provides the solution of the network for a fault on selected buses. The printout shown is for the first cycle fault calculation using 1.0 p.u. driving voltage and does not include prefault steady-state load currents. The sample printout is for a program that calculates the fault current based on a complex $(R + jX)$ impedance reduction and the asymmetry current multipliers based on X/R ratio from separate R and X network reductions. The output format is described as follows:

```
* Bus: XXX ***** (A)
  XX.XX KA AT XX.XX DEG. (XXX.X MVA) X/R = XX.XX KV = XX.XXX
    (B)          (C)          (D)          (E)          (F)
  Ze = X.XXXXX +j X.XXXXX (Complex) (G)
  SYM*1.6 = XX.XX          ASYM Based on X/R ratio = XX.XX
    (H)                                (I)
```

- a) Faulted bus as referenced on the one-line diagram.
- b) The value of symmetrical current for a three-phase fault on the referenced bus based on complex impedance network reduction.
- c) The angle between the real component of the fault current and the total fault current.
- d) The fault MVA value corresponding to the symmetrical fault current.
- e) The ratio of the equivalent fault point reactance to the equivalent fault point resistance by separate R and X network reductions.
- f) The nominal prefault bus voltage.
- g) The equivalent fault point impedance.
- h) The bus asymmetrical fault current duty as suggested from IEEE Std C37.010 [B3], for buses over 1 kV using 1.6 asymmetry factor.
- i) The bus asymmetrical fault current duty based on the fault point X/R ratio for buses over 1 kV.

CONTRIBUTIONS TO FAULT:

BUS to	BUS	MAG	ANG	BUS to	BUS	MAG	ANG
AAAAA	BBBBB	XX.XXX	XX.XX	CCCCC	BBBBB	X.XXX	XX.XXX
(J)	(K)	(L)	(M)	(J)	(K)	(L)	(M)

- j) & k) Buses between which the fault current flow is calculated, as referenced to the one-line diagram. Buses listed as "0" are sources such as a utility, a generator, or a motor.
- l) The magnitude of fault current flow between the listed buses.
- m) The angle of fault current flow between the listed buses.

4.6.1 Raw data printout

The raw data listing for the enclosed one-line diagram is given in Table 4-5 through Table 4-12. This data is for the complete system and will be used in this and subsequent chapters. In this chapter, the generators and motors are not considered to be connected to the system. The only source of short-circuit current is the utility connection. In reference to the one-line diagram, a motor identified as HPC (Horse Power Combined) is a combination of motors in the size category listed. For example, the motor identified as M-30 below is specified as 200 HP, while the size is ≥ 50 HP. This could be the combination of 2–100 HP motors or 2–75 HP and 1–50 HP motors.

Table 4-5—Utility system data

Identifier	Bus	Base kV	3 ϕ fault MVA	3 ϕ fault X/R ratio	1 ϕ (L-G) fault MVA	1 ϕ (L-G) X/R ratio
UTIL-1	100:UTIL-6	69.0	1000.0	22.2	765.0	70.0

Table 4-6—Generator data

Identifier	Bus	Rating MVA	Base kV	RPM	Rated PF	3 ϕ %X	3 ϕ X/R	1 ϕ (L-G) %X	1 ϕ (L-G) X/R
GEN-2	04:MILL-2	12.5	13.8	3600	0.8	12.8	35.7	5.8	35.7
GEN-1	50:GEN1	15.625	13.8	3600	0.8	11.2	37.4	5.7	37.4

Table 4-7—Motor data

Identifier	Bus	HP	kVA	Type	RPM	PF	Base kV	%X	X/R
M-30	51: AUX	200	200	IND> 50	1800	—	0.48	16.7	7
M-31	51: AUX	600	570	IND< 50	1800	—	0.48	16.7	12
M-FDR-L	08:FDR L	9000	9000	SYN	1800	0.8	13.8	20	34
M-T10-1	28:T10 SEC	400	400	IND< 50	1800	—	0.48	16.7	10
M-T10-2	28:T10 SEC	500	500	IND> 50	1800	—	0.48	16.7	5
M-T10-3	33:T10MCC	300	287.5	IND< 50	1800	—	0.48	16.7	12
M-T11-1	29:T11 SEC	625	625	IND> 50	1800	—	0.48	16.7	10
M-T11-2	29:T11 SEC	465	465	IND< 50	1800	—	0.48	16.7	5
M-T11-3	34:T11MCC	110	110	IND< 50	1800	—	0.48	16.7	7
M-T12-1	30:T12 SEC	400	387.9	IND> 50	1800	—	0.48	16.7	12
M-T12-2	30:T12 SEC	500	500	IND< 50	1800	—	0.48	16.7	5
M-T12-3	35:T12MCC	300	287.5	IND< 50	1800	—	0.48	16.7	12
M-T13-1	36:T13 SEC	2500	2250	IND> 50	1800	—	2.3	16.7	32.85
M-T14-1	37:T14 SEC	700	678.8	IND> 50	1800	—	0.48	16.7	12
M-T14-2	37:T14 SEC	300	300	IND< 50	1800	—	0.48	16.7	5
M-T17-1	49:RECT	1200	1200	IND< 50	1800	—	0.46	29.9	8
M-T3-1	39:T3 SEC	1750	1662.5	IND>1000	1800	—	4.16	16.7	29.74
M-T4-1	11:T4 SEC	500	475	IND> 50	1800	—	2.4	16.7	12
M-T5-1	17:T5 SEC	850	824.2	IND< 50	1800	—	0.48	16.7	10
M-T5-2	17:T5 SEC	500	500	IND> 50	1800	—	0.48	16.7	5
M-T5-3	22:T5MCC	150	142.5	IND< 50	1800	—	0.48	16.7	14
M-T6-1	18:T6 SEC	850	824.2	IND< 50	1800	—	0.48	16.7	10
M-T6-2	18:T6 SEC	500	500	IND> 50	1800	—	0.48	16.7	5
M-T6-3	23:T6MCC	150	142.5	IND< 50	1800	—	0.48	16.7	14
M-T7-1	19:T7 SEC	1250	1125	IND>1000	1800	—	2.4	16.7	26.1
M-T7-2	19:T7 SEC	2500	2375	IND>1000	1800	—	2.4	16.7	15
M-T8-1	20:T8 SEC	1750	1662.5	IND>1000	1800	—	2.4	16.7	15
M-T8-2	20:T8 SEC	2000	1800	IND>1000	1800	—	2.4	28	26
M-T9-1	21:T9 SEC	750	727.3	IND< 50	1800	—	0.48	16.7	12

Table 4-8—Transformer data

Identifier	kVA	%Z1	X/R (+)	%Z0	X/R (0)	kV	Tap	From bus	To bus
T-1	15000	8	17	7.2	17	69/13.8	69	01:69-1	03:MILL-1
T-2	15000	8	17	7.4	17	69/13.8	69	02:69-2	04:MILL-2
T-3	1725	6	8	6	8	13.8/4.16	13.8	05:FDR F	39:T3 SEC
T-4	1500	5.5	6.5	5.5	6.5	13.8/2.4	13.8	06:FDR H	11:T4 SEC
T-5	1500	6.75	6.5	6.75	6.5	13.8/0.48	13.8	12:T5 PRI	17:T5 SEC
T-6	1500	5.75	6.5	5.75	6.5	13.8/0.48	13.8	13:T6 PRI	18:T6 SEC
T-7	3750	5.5	12	5.5	12	13.8/2.4	13.8	06:FDR H	19:T7 SEC
T-8	3750	5.5	12	5.5	12	13.8/2.4	13.8	15:FDR I	20:T8 SEC
T-9	750	5.75	5	5.5	5	13.8/0.48	13.8	16:T9 PRI	21:T9 SEC
T-10	1500	5.75	6.5	5.75	6.5	13.8/0.48	13.8	25:T10 PRI	28:T10 SEC
T-11	1500	5.75	6.5	5.5	6.5	13.8/0.48	13.8	26:FDR G	29:T11 SEC
T-12	1500	5.75	6.5	5.5	6.5	13.8/0.48	13.8	27:T12 PRI	30:T12 SEC
T-13	2500	5.75	10	50	10	13.8/2.4	13.8	31:FDR P	36:T13 SEC
T-14	1000	5.75	5.5	50	5.5	13.8/0.48	13.8	32:FDR Q	37:T14 SEC
T-17	1250	4.5	6	4.5	6	13.8/0.48	13.8	05:FDR F	49:RECT
T-18	1500	5.75	5.91	5.75	5.91	13.8/0.48	13.8	50:GEN1	51:AUX

Table 4-9—Current-limiting reactor data

Identifier	Through kVA	Amps	Ohms	Material	kV	%Z	X/R	Bus
CLL-3	23903	1000.0	0.8	Copper	13.8	3.35	100	04:MILL-2

Table 4-10—Cable data

Identifier	Description (kemil)	Material	Length (ft)	Length (m)	kV	From bus	To bus
C-E1	1-3/C-250	CU PVC	650	198.1	13.8	03:MILL-1	09:FDR E
C-E2	1-3/C-250	CU PVC	1833	558.7	13.8	09:FDR E	25:T10PRI
C-E3	1-3/C-250	CU PVC	75	22.9	13.8	09:FDR E	13:T6PRI
C-E4	1-3/C-250	CU PVC	165	50.3	13.8	09:FDR E	12:T5PRI
C-F1	1-3/C-250	CU PVC	325	99.1	13.8	03:MILL-1	05:FDR F
C-G1	1-3/C-250	CU PVC	680	207.3	13.8	03:MILL-1	26:FDR G
C-H1	1-3/C-250	CU PVC	471	143.6	13.8	03:MILL-1	06:FDR H
C-I1	1-3/C-250	CU PVC	980	298.7	13.8	04:MILL-2	15:FDR I
C-J2	1-3/C-250	CU PVC	619	188.7	13.8	04:MILL-2	27:T12 PRI
C-J3	1-3/C-250	CU PVC	1187	361.8	13.8	16:T9 PRI	04:MILL-2
C-J4	1-3/C-250	CU PVC	200	61	13.8	10:EMERG	13:T6 PRI
C-J5	1-3/C-250	CU Steel	10	3	13.8	10:EMERG	12:T5 PRI
C-J6	1-3/C-250	CU PVC	475	144.8	13.8	10:EMERG	27:T12 PRI
C-L1	1-3/C-400	CU PVC	510	155.4	13.8	04:MILL-2	08:FDR L
C-M1	1-3/C-250	CU PVC	510	155.4	13.8	04:MILL-2	24:FDR M
C-M2	1-3/C-250	CU PVC	340	103.6	13.8	24:FDR M	31:FDR P
C-M3	1-3/C-250	CU PVC	485	147.8	13.8	24:FDR M	32:FDR Q
C-T10-1	2-3/C-400	CU PVC	50	15.2	0.48	28:T10 SEC	38:480TIE
C-T10-2	1-3/C-250	CU PVC	20	6.1	0.48	33:T10MCC	28:T10SEC
C-T11-1	2-3/C-400	CU PVC	66	20.1	0.48	29:T11 SEC	38:480TIE
C-T11-2	1-3/C-250	CU PVC	20	6.1	0.48	34:T11MCC	29:T11SEC
C-T12-1	1-3/C-400	CU PVC	50	15.2	0.48	38:480 TIE	30:T12SEC
C-T12-2	1-3/C-250	CU PVC	20	6.1	0.48	35:T12MCC	30:T12SEC
C-T5-1	1-3/C-250	CU PVC	20	6.1	0.48	22:T5MCC	17:T5 SEC
C-T6-1	1-3/C-250	CU PVC	20	6.1	0.48	23:T6MCC	18:T6 SEC
C1A	2-1/C-500	CU PVC	2000	609.6	13.8	50:GEN1	03:MILL-1

Table 4-11—Transmission line data

Identifier	Description (kcmil)	Material	GMD	Length (mi)	Length (m)	kV	From bus	To bus
L-1	266.8	ACSR	7.0	1.894	3048	69.0	100:UTIL-69	01:69-1
L-2	266.8	ACSR	7.0	1.894	3048	69.0	100:UTIL-69	02:69-2

Table 4-12—Busway data

Identifier	Manuf.	Length (ft)	Length (m)	Amps	kV	R	X	Mat.	From bus	To bus
BWY-1	SQD-I-Li	50.0	15.2	1000	0.48	0.0008	0.0005	CU	28:T1 0SEC	41:L CTS

4.6.2 Per-unit data

The following tables summarize the raw data in the form of per-unit data on a 10 MVA base. The utility system, generators, and motors have the impedances given in Table 4-13 for the first cycle and interrupting time calculations. The branch data, also in per-unit on a 10 MVA base, is shown in Table 4-14. Taken together, the data in these two tables are for the complete system and will be used in this and subsequent chapters.

**Table 4-13—Per-unit source (utility, generator, and motor)
(per-unit on 10 MVA base)**

Bus	Description	First cycle		Interrupting	
		R	X	R	X
100:UTIL-69	Util.	0.00045	0.00999	0.00045	0.00999
04:MILL-2	Gen.	0.00287	0.1024	0.00287	0.1024
50:GEN1	Gen.	0.00192	0.07168	0.00192	0.07168
51: AUX	Med Ind	1.43143	10.02	3.57858	25.05
51: AUX	Sm Ind	0.40773	4.89278	—	—
08:FDR L	Syn Mot	0.00654	0.22222	0.00981	0.33333
28:T10 SEC	Sm Ind	0.69722	6.97225	—	—
28:T10 SEC	Med Ind	0.8016	4.008	2.004	10.02

Table 4-13—Per-unit source (utility, generator, and motor)
(per-unit on 10 MVA base) (continued)

Bus	Description	First cycle		Interrupting	
		<i>R</i>	<i>X</i>	<i>R</i>	<i>X</i>
33:T10MCC	Sm Ind	0.8084	9.70071	—	—
29:T11 SEC	Med Ind	0.32064	3.2064	0.8016	8.016
29:T11 SEC	Sm Ind	1.19953	5.99764	—	—
34:T11MCC	Sm Ind	3.62195	25.35361	—	—
30:T12 SEC	Med Ind	0.43055	5.16656	1.07637	12.91641
30:T12 SEC	Sm Ind	1.11556	5.5778	—	—
35:T12MCC	Sm Ind	0.8084	9.70071	—	—
36:T13 SEC	Med Ind	0.0249	0.818	0.06225	2.04501
37:T14 SEC	Med Ind	0.24602	2.95232	0.61506	7.38081
37:T14 SEC	Sm Ind	1.85928	9.29634	—	—
49:RECT	Sm Ind	0.47769	3.82154	—	—
39:T3 SEC	Lg Ind	0.03378	1.0045	0.05067	1.50675
11:T4 SEC	Med Ind	0.35158	4.21892	0.87894	10.54731
17:T5 SEC	Sm Ind	0.33836	3.38359	—	—
17:T5 SEC	Med Ind	0.8016	4.008	2.004	10.02
22:T5MCC	Sm Ind	1.39794	19.5711	—	—
18:T6 SEC	Sm Ind	0.33836	3.38359	—	—
18:T6 SEC	Med Ind	0.8016	4.008	2.004	10.02
23:T6MCC	Sm Ind	1.39794	19.5711	—	—
19:T7 SEC	Lg Ind	0.05688	1.48446	0.08532	2.22669
19:T7 SEC	Lg Ind	0.04688	0.70315	0.07032	1.05472
20:T8 SEC	Lg Ind	0.06697	1.0045	0.10046	1.50675
20:T8 SEC	Lg Ind	0.05983	1.55557	0.08975	2.33335
21:T9 SEC	Sm Ind	0.31955	3.83474	—	—

Table 4-14—Per-unit impedances for all branches

From bus	To bus	<i>R</i>	<i>X</i>	Equipment description
01:69-1	03:MILL-1	0.00313	0.05324	Transf T-1
02:69-2	04:MILL-2	0.00313	0.05324	Transf T-2
05:FDR F	39:T3 SEC	0.04314	0.34514	Transf T-3
06:FDR H	11:T4 SEC	0.05575	0.3624	Transf T-4
12:T5 PRI	17:T5 SEC	0.06843	0.44477	Transf T-5
13:T6 PRI	18:T6 SEC	0.05829	0.37888	Transf T-6
06:FDR H	19:T7 SEC	0.14616	0.14616	Transf T-7
15:FDR I	20:T8 SEC	0.14616	0.14616	Transf T-8
16:T9 PRI	21:T9 SEC	0.15036	0.75178	Transf T-9
25:T10 PRI	28:T10 SEC	0.05829	0.37888	Transf T-10
26:FDR G	29:T11 SEC	0.05829	0.37888	Transf T-11
27:T12 PRI	30:T12 SEC	0.05829	0.37888	Transf T-12
31:FDR P	36:T13 SEC	0.02289	0.22886	Transf T-13
32:FDR Q	37:T14 SEC	0.10286	0.56573	Transf T-14
05:FDR F	49:RECT	0.05918	0.3551	Transf T-17
50:GEN1	51: AUX	0.06391	0.37797	Transf T-18
03:MILL-1	09:FDR E	0.0015	0.00125	Cable C-E1
09:FDR E	25:T10 PRI	0.00424	0.00353	Cable C-E2
09:FDR E	13:T6 PRI	0.00017	0.00014	Cable C-E3
09:FDR E	12:T5 PRI	0.00038	0.00032	Cable C-E4
03:MILL-1	05:FDR F	0.00075	0.00063	Cable C-F1
03:MILL-1	26:FDR G	0.00157	0.00131	Cable C-G1
03:MILL-1	06:FDR H	0.00109	0.00091	Cable C-H1
04:MILL-2	15:FDR I	0.00227	0.00189	Cable C-I1
04:MILL-2	27:T12 PRI	0.00143	0.00119	Cable C-J2
16:T9 PRI	04:MILL-2	0.00275	0.00229	Cable C-J3
10:EMERG	13:T6 PRI	0.00046	0.00039	Cable C-J4
10:EMERG	12:T5 PRI	0.00002	0.00002	Cable C-J5
10:EMERG	27:T12 PRI	0.0011	0.00091	Cable C-J6

Table 4-14—Per-unit impedances for all branches (continued)

From bus	To bus	R	X	Equipment description
04:MILL-2	08:FDR L	0.00076	0.00092	Cable C-L1
04:MILL-2	24:FDR M	0.00118	0.00098	Cable C-M1
24:FDR M	31:FDR P	0.00079	0.00065	Cable C-M2
24:FDR M	32:FDR Q	0.00112	0.00093	Cable C-M3
28:T10 SEC	38:480 TIE	0.03039	0.02929	Cable C-T10-1
33:T10MCC	28:T10 SEC	0.03813	0.0245	Cable C-T10-2
29:T11 SEC	38:480 TIE	0.04012	0.03866	Cable C-T11-1
34:T11MCC	29:T11 SEC	0.03813	0.0245	Cable C-T11-2
38:480 TIE	30:T12 SEC	0.06079	0.05858	Cable C-T12-1
35:T12MCC	30:T12 SEC	0.03813	0.0245	Cable C-T12-2
22:T5MCC	17:T5 SEC	0.03813	0.0245	Cable C-T5-1
23:T6MCC	18:T6 SEC	0.03813	0.0245	Cable C-T6-1
50:GEN1	03:MILL-1	0.00122	0.00243	Cable C1A'
100:UTIL-69	01:69-1	0.00139	0.00296	T-Line L-1
100:UTIL-69	02:69-2	0.00139	0.00296	T-Line L-2
28:T10 SEC	41:LGTS	0.03429	0.02094	Bwy-1

4.6.3 Computer short-circuit printout

In this subclause, sample computer-generated results are provided. These results are not intended to be complete. Rather, they are intended to provide a sample of the type of data that is produced by a wide variety of commercially-available short-circuit programs. Because of the built-in assumptions that many programs make, these samples should not be used for benchmarking purposes.

FAULT LEVEL IN KILOAMPS

```
***** BUS: 100 :UTIL-69 *****
      8.367 KA AT -87.42 DEG ( 999.99 MVA): X/R = 22.20 KV = 69.000
      Ze = 0.0004503 +j 0.0099900 (Complex)
      SYM kA*1.6 = 13.39      ASYM kA Based on X/R ratio = 13.27 kA
```

CONTRIBUTIONS TO FAULT:

BUS	to	BUS	MAG	ANG	BUS	to	BUS	MAG	ANG
UTIL		100:UTIL69	8.367	???	01:69-1		100:UTIL69	0.000	-3.70
02:69-2		100:UTIL69	0.000	???					

***** BUS: 01:69-1 *****

6.397 KA AT -81.91 DEG (764.53 MVA): X/R = 7.04 KV = 69.000
Ze = 0.0018405 +j 0.0129498 (Complex)
SYM kA*1.6 = 10.24 ASYM kA Based on X/R ratio = 8.70 kA

CONTRIBUTIONS TO FAULT:

BUS to	BUS	MAG	ANG	BUS to	BUS	MAG	ANG
01:69-1	03:MILL-1	-0.000	-3.37	01:69-1	100:UTIL69	-6.397	-81.91

***** BUS: 02:69-2 *****

6.397 KA AT -81.91 DEG (764.52 MVA): X/R = 7.04 KV = 69.000
Ze = 0.0018403 +j 0.0129500 (Complex)
SYM kA*1.6 = 10.24 ASYM kA Based on X/R ratio = 8.70 kA

CONTRIBUTIONS TO FAULT:

BUS to	BUS	MAG	ANG	BUS to	BUS	MAG	ANG
02:69-2	04:MILL-2	0.000	0.00	02:69-2	100:UTIL69	-6.397	-81.91

***** BUS: 03:MILL-1 *****

6.303 KA AT -85.69 DEG (150.66 MVA): X/R = 13.32 KV = 13.800
Ze = 0.0049843 +j 0.0661870 (Complex)
SYM kA*1.6 = 10.09 ASYM kA Based on X/R ratio = 9.48 kA

BUS to	BUS	MAG	ANG	BUS to	BUS	MAG	ANG
--------	-----	-----	-----	--------	-----	-----	-----

CONTRIBUTIONS TO FAULT:

BUS to	BUS	MAG	ANG	BUS to	BUS	MAG	ANG
01:69-1	03:MILL-1	6.303	-85.71	03:MILL-1	09:FDR E	-0.001	0.11
03:MILL-1	05:FDR F	0.000	0.00	03:MILL-1	26:FDR G	0.000	0.00
03:MILL-1	06:FDR H	0.000	0.00	03:MILL-1	50:GEN1	0.000	0.00

4.7 Conclusions

In this chapter, the most basic short-circuit calculation techniques have been presented. While only calculations that do not consider ac decay (NACD) have been considered, the basic techniques and methods apply to the more complex calculations that are the subject of future chapters. The data provided for the example system has been presented in its entirety, and this data will be used extensively in subsequent chapters. The calculation techniques for balanced three-phase faults with no ac decay have been demonstrated with "hand" examples, and a brief sample of the types of results available from standard commercial-grade short-circuit programs has been provided for informative purposes.

4.8 Bibliography

- [B1] IEC 909:1977, German National Committee Report No. 73: Short-Circuit Currents.²
- [B2] IEEE Std 399TM-1997, IEEE Recommended Practices for Power System Analysis (*IEEE Brown Book*).^{3, 4}
- [B3] IEEE Std C37.010TM-1999 (Reaff 2005), IEEE Guide for AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis.

²IEC publications are available from the Sales Department of the International Electrotechnical Commission, Case Postale 131, 3, rue de Varembe, CH-1211, Genève 20, Switzerland/Suisse (<http://www.iec.ch/>). IEC publications are also available in the United States from the Sales Department, American National Standards Institute, 11 West 42nd Street, 13th Floor, New York, NY 10036, USA.

³IEEE publications are available from the Institute of Electrical and Electronics Engineers, 445 Hoes Lane, P.O. Box 1331, Piscataway, NJ 08855-1331, USA (<http://standards.ieee.org/>).

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Chapter 5

Calculating ac short-circuit currents for systems with contributions from synchronous machines

5.1 Introduction

This chapter describes the calculations of three-phase short-circuit currents for systems with ac current decay from synchronous machines. This could be applicable to utilities and larger industrial systems.

This chapter is limited to the consideration of short-circuit currents that occur under the following conditions:

- 1) Short-circuit fault currents that occur in low-voltage ac systems and medium-voltage ac systems operating at a constant frequency.
- 2) For the duration of the short circuit, there is no change in the source driving voltage or voltages that caused the initial short-circuit current to flow.
- 3) The fault impedance is zero and has no current limiting effect.
- 4) Synchronous machine fault current contribution varies with time after the fault and is not negligible.
- 5) For simplification, only three-phase faults will be considered. Unbalanced faults are covered in a later chapter.

5.2 Purpose

The objective of this chapter is to give recommended standardized procedures for the calculation of short-circuit currents on systems with ac decay from synchronous machines. The application and selection of interrupting equipment based on the calculated fault current on a total system is covered in Chapter 10. Fault currents with no ac fault current decay are covered in Chapter 4 and fault currents from induction machines are covered in Chapter 6. AC current decay calculations add a small amount of complexity to the no ac decay fault calculations. The sample one-line diagram used to show the calculations is the same as used in Chapter 4 except with synchronous machines added. Hand and computer generated calculations will be made at several buses.

5.3 ANSI guidelines

The generator reactances used in this chapter will be based on the first cycle and interrupting reactances as given in IEEE Std C37.010™-1999 [B3].¹ The representation of synchronous machines by a varying reactance is easily adapted to other analytical techniques, such as IEC 909:1977 [B2]. Because of the decaying nature of the ac currents, a first cycle and an interrupting time calculation may be needed for equipment evaluation.

¹The numbers in brackets correspond to those of the bibliography in 5.12.

IEEE Std C37.010™-1999 [B3] includes three system conditions (in addition to the use of reactance multipliers) to be used when calculating fault currents when ac decay is present. These are:

- 1) The pre-fault bus voltage is 1.0 p.u.
- 2) Separate resistance and reactance networks are to be used to determine the fault point X/R ratio. This X_{sep}/R_{sep} ratio is to be used to calculate the total asymmetrical fault current. Option: Z/R_{sep} can be considered the same as X_{sep}/R_{sep} .
- 3) Load currents are much smaller than the fault current and are neglected.

5.4 Fault calculations

The basic procedure for making calculations in systems where ac decay is to be included is the same as discussed previously in Chapter 2 and Chapter 4. Both the symmetrical and asymmetrical fault currents are of interest, and the same calculations and formulas apply. The only difference arises when interrupting time calculations are made; reactance multipliers used to account for ac decay are used to increase the impedance of synchronous machines. This change in impedance of a major source of fault current (the synchronous machine) will increase the equivalent impedance seen at any fault point and therefore directly impact calculated results.

5.5 Nature of synchronous machine contributions

A running synchronous machine that has a bolted three-phase short circuit suddenly connected across its terminals will contribute currents to the short circuit. A typical fault current plot (without dc decay) is shown in Figure 5-1. The plot shows a high initial decay followed by a slower rate of decay and finally a steady-state value.

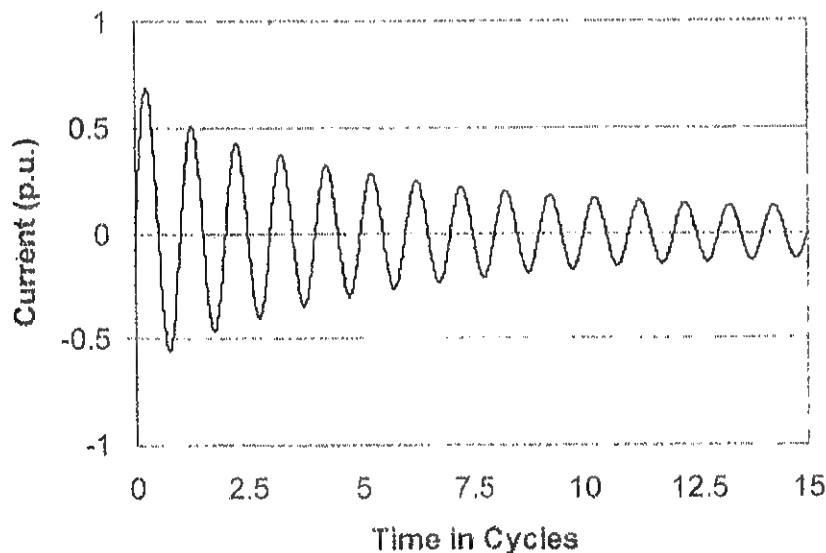


Figure 5-1—Three-phase short-circuit currents from a synchronous machine

The short-circuit current decreases exponentially in time from an initially high value to a lower steady-state level. This happens because the flux across the air gap of the synchronous machine is much larger at the instant the short-circuit occurs than it is a few cycles later. As the air-gap flux reduces because of limited field current capability, the stator current decreases. The internal voltage generated by the air-gap flux determines the magnitude of the short-circuit current. This changing air-gap flux accounts for the gradual decrease in the short-circuit current as shown in Figure 5-1.

The rate of decay and the steady-state fault current depend upon the synchronous machine time constants and the regulating action of the field current, if any. The initial current contribution is caused by an internal stator driving voltage generated by trapped rotor field flux. The current to the terminal short circuit is limited by the internal impedance of the machine. The current in two or all three phases is asymmetrical at first, and consists of an ac and a dc component.

The ac component decays because the rotor flux is not maintained by the normal applied field voltage. The dc component, a transient not supported by any driving voltage, also decays. The initial frequency of the fault current is the same as system frequency and is directly related to rotor speed. Thereafter, the frequency of the fault current from a motor reduces at a rate dependent on motor mechanical load and combined motor and load inertia while those of a generator will increase based on the turbine power and combined turbine and generator inertia. For the first few cycles after the short circuit, the frequency change is usually conservatively considered to be inconsequential.

The equivalent circuit used to represent a synchronous machine or a group of synchronous machines in simplified short-circuit calculations is shown in Figure 5-2. For calculations based on Thevenin's theorem, the equivalent circuit of the complete system containing several synchronous machines is reduced to a single driving voltage in series with an equivalent impedance.

As described previously, the synchronous machine driving voltages are not constant. They change with time depending on machine loading, excitation voltage, and system conditions. The machine impedances depend upon the physical design of the machine and are essentially constant. They do change with temperature and frequency.

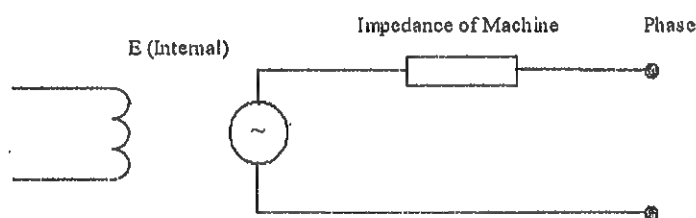


Figure 5-2—Synchronous machine per phase equivalent circuit

One simplified calculation technique of increasing the reactance from X''_{dv} in increments as time passes after the short circuit is initiated accounts for the ac current decay, assuming the voltage is constant. This model obtains the machine decaying ac current contributions in the equivalent circuit without changing the circuit driving voltage. This technique is widely used and accepted by the industry. Typical reactance multiplying factors to be applied to X''_{dv} depend on whether the synchronous machine is a generator or a motor. Typical reactance multiplying factors are given in Table 5-1. Definitions of synchronous machine reactance are given in Chapter 1 and reviewed in this chapter.

The initial magnitude of the ac component is calculated using the subtransient reactance X''_{dv} of the machine. The initial magnitude of the dc component for short-circuit calculations is equal to the crest value of the initial ac component, assuming the fault current in one phase has the maximum possible asymmetry. Depending on the synchronous machine time constants, the transition of fault current from subtransient to transient to synchronous will vary and will generally take longer to decay than an induction motor current as described in Chapter 6. If the field to the machine remains energized, then a steady-state fault current will exist due to continuous replenishing of stator flux energy that is removed by the fault. Otherwise, the fault current from a synchronous machine will decay to zero.

Typical reactances of synchronous motors when the actual reactance is not available are given in Table 5-2.

Table 5-1—Synchronous machine reactances and multiplying factors from IEEE Std C37.010 [B3] and IEEE Std C37.13™ [B2]

Type of machine	Medium voltage and high voltage per IEEE Std C37.010	Low voltage per IEEE Std C37.13
First cycle calculations		
Remote utility	$1.0 \times X_s$	$1.0 \times X_s$
Local generator	$1.0 \times X''_{dv}$	$1.0 \times X''_{dv}$
Synchronous motor	$1.0 \times X''_{dv}$	$1.0 \times X''_{dv}$
Interrupting time calculations (3–5 cycles)		
Remote utility	$1.0 \times X_s$	a
Local generator	$1.0 \times X''_{dv}$	a
Synchronous motor	$1.5 \times X''_{dv}$	a

^a3–5 cycle interrupting times do not apply to low-voltage breakers.

Table 5-2—Synchronous machine typical reactances

Number of poles	60 Hz RPM	X''_{dv} reactance
> 16	≤ 450	28%
8–14	514–900	20%
2–6	≥ 1200	15%

Most synchronous machines fall into one of the following three categories:

- 1) Synchronous generators
- 2) Synchronous condensers
- 3) Synchronous motors

Synchronous generators are a principal source of electrical energy in power systems because almost all utilities use synchronous generators to generate electricity. Many of the larger industrial systems may include generators for energy conservation such as in co-generation.

Synchronous condensers are used as a means of reducing power system transmission losses, reactive power control and controlling voltages in a transmission or distribution system. They are connected to the power system as a motor but are neither connected to a load nor to a prime mover. Modern equipment such as static var compensators (SVCs) are much more common today than synchronous condensers, but the older rotating compensators may still be occasionally encountered in practice.

Synchronous motors are generally used to drive large loads such as compressors, pumps, and M-G sets and to supply capacitive power for power factor improvement. Sometimes synchronous motors are operated near unity power factor and rarely are operated drawing reactive power from system. The motors can have fixed or constant current fields or can have regulators that control bus voltage or motor power factor.

5.6 Synchronous machine reactances

Synchronous machines have a number of reactances and time constants that can be used when modeling the machine. For short-circuit studies, these normally are reduced to the following:

- 1) X''_{dv} – Subtransient reactance (saturated)
- 2) X'_{dv} – Transient reactance (saturated)
- 3) X_d – Synchronous reactance (saturated)
- 4) X_{2v} – Negative sequence reactance (saturated)
- 5) X_{0v} – Zero sequence reactance (saturated)
- 6) T_{a3} – Three-phase short-circuit time constant
- 7) T''_{do}, T'_{do} – Subtransient and transient time constants

The definitions are as follows:

- a) Direct-axis saturated subtransient reactance (X''_{dv}) is the apparent reactance of the stator winding at the instant short-circuit occurs with the machine at rated voltage, no load. This reactance determines the current flow during the first few cycles after short-circuit initiation.
- b) Direct-axis saturated transient reactance (X'_{dv}) is the apparent reactance of the stator winding several cycles after initiation of the fault with the machine at rated voltage, no load. The time period for which the reactance may be considered X'_{dv} can be up to a half (1/2) second or longer, depending upon the design of the machine and is determined by the machine direct-axis transient time constant.
- c) Direct-axis synchronous reactance X_d is the ratio of the fundamental-frequency component of reactive armature voltage (V_d) to the fundamental-frequency direct-axis positive-sequence component of armature current (I_{1d}) under sustained balanced conditions with rated field current applied.
- d) Negative sequence reactance is the apparent reactance determined by placing a line-to-line fault on the terminal of the generator at rated voltage. The negative sequence reactance is calculated knowing the direct-axis reactances by symmetrical components.
- e) Zero sequence reactance is the apparent reactance determined by placing a line-to-ground fault on the terminal of the generator so that rated current flows. Test are done at reduced voltage. The zero sequence reactance is calculated using the direct-axis and negative sequence reactances and symmetrical components.
- f) Three-phase short-circuit armature time constant is the time required for the ac short-circuit current to decay to 36.8% of its initial value. This time constant is a combination of the subtransient and transient time constants.
- g) Subtransient and Transient time constants are the times required for the respective components of subtransient and transient currents to decay to 36.8% of their initial value.

The most important characteristics of synchronous machines when calculating short-circuit currents are the internal reactances and resistances. In practice, a single machine reactance is assumed to vary (with time) from a subtransient to a transient to a sustained or steady-state impedance; these variations control the ac component of the fault current. The resistance controls the dc rate of decay. The machine time constants that determine the rate of ac decay of the components of current are also important.

Expression of the synchronous machine variable reactance at any instant requires a complicated formula involving time as one of the variables. However, for the sake of simplicity the reactance is considered fixed over the time interval for which the fault current is calculated. An expression of the ac rms current verses time for a three-phase short-circuit at the terminals of a synchronous machine is as follows in Equation (5.1):

$$I_{sc} = \left(\frac{E}{X''_{dv}} - \frac{E}{X'_{dv}} \right) e^{-\frac{t}{T''_{dv}}} + \left(\frac{E}{X'_{dv}} - \frac{E}{X_d} \right) e^{-\frac{t}{T'_{dv}}} + \frac{E}{X_d} \quad (5.1)$$

where t is in seconds and voltage and reactances are (typically) in per-unit.

For a fault occurring away from the machine terminals, Equation (5.1) would have to include the transfer impedance between the machine and the fault. In addition, the resistance of the network would effect the decay time constants. Providing this detail in short-circuit calculations would be very burdensome, thus the desire for simplicity while maintaining conservatism.

5.7 One-line diagram data

The raw data, per-unit data, and one-line used is given in Chapter 4. The one-line diagram from this chapter adds two generators, one at bus 04:MILL-2 and the other at bus 50:GEN1, and a large synchronous motor at bus 08:M-FDR-L. These are the decaying ac fault sources along with the non-decaying utility source that provide short-circuit current to a faulted bus.

5.8 Sample calculations

5.8.1 Sample calculation #1

In this example, a fault is placed on 2.4 kV bus 36:T13 SEC. The total impedance to the fault is the reduction of all circuit and source impedances to the fault point. The total fault impedance is affected by the synchronous machines connected to MILL-1 and MILL-2 buses. This reduces, as compared to the sample calculation in Chapter 4, the effective impedance between the utility and MILL-2 bus and increases the fault level at bus 36:T13 SEC. Figure 5-3 provides a reduced one-line diagram showing the critical pieces of data required. The impedance data needed for the network reduction is given in Chapter 4.

Equivalents need to be made for both a first cycle and an interrupting time calculation. One equivalent is Generator 1 to the common connection point of bus 100:UTIL-69. The connection would be 04:MILL-2 if the tie breaker 03:MILL-1 to 04:MILL-2 was closed. The second equivalent is motor M-FDR L to bus 04:MILL-2. Because none of the other motor sources are assumed to be connected, the equivalent source impedance in this case is the sum of the series impedances between the machine internal source voltages and the common connection points. The equivalent motor source impedance is provided on the reduced one-line diagram. The actual series and parallel network reduction to obtain the equivalents is not shown. The calculations for the fault current on bus 36:T13SEC are given on following pages. The manual calculations provide the current magnitudes using separate R and X network reductions while the computer printout uses the complex network reduction for current and separate R and X network reductions for the X/R ratio.

In a system with sources that have a decaying ac component, both first cycle and interrupting time calculations are required for the high-voltage buses. To accomplish both sets of calculations, the source and equivalent impedances shown in Figure 5-3 are required for both time periods. The cumulative impedance sums, down to the fault bus for both first cycle and interrupting calculations, are shown in Table 5-3.

The symmetrical fault current via Trans T-13 is shown in Table 5-4.

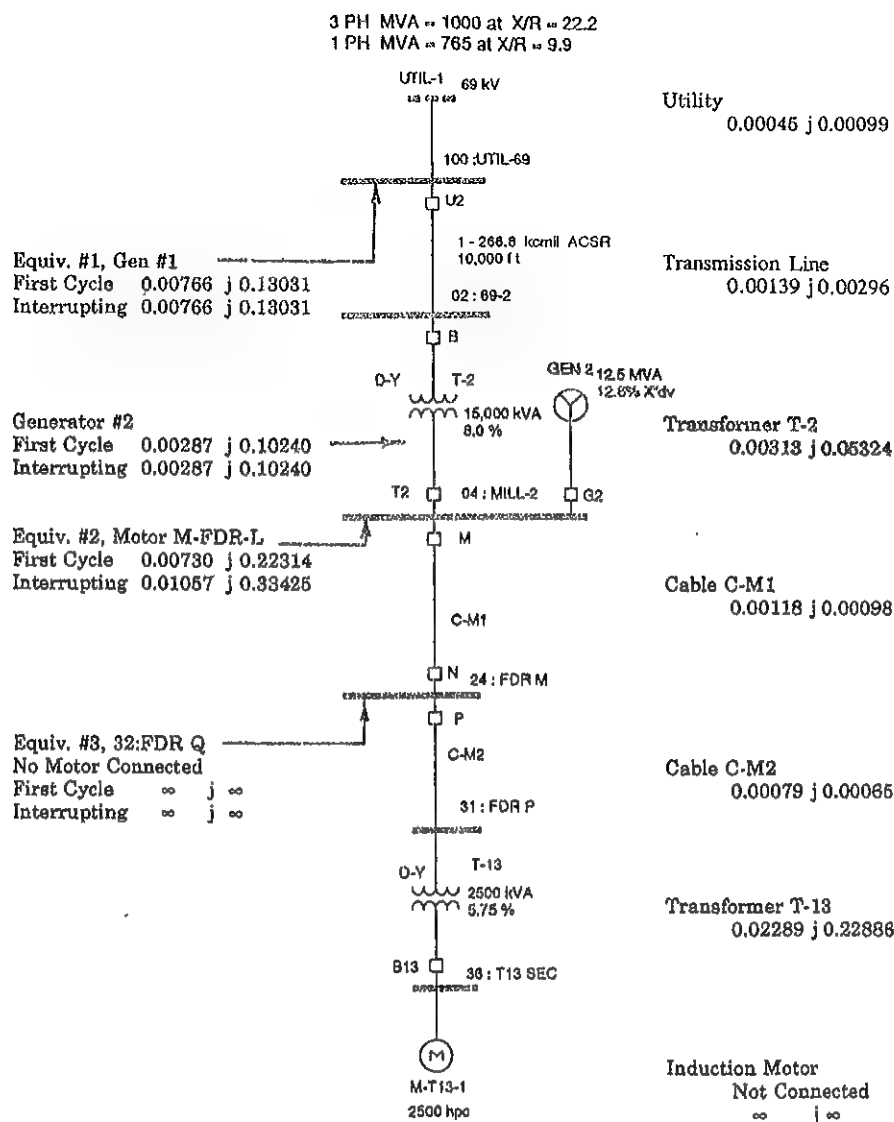


Figure 5-3—Equivalents and impedance one-line diagram for sample calculations

Table 5-3— R & X per-unit calculations for first cycle and interrupting time

	First cycle		Interrupting time		
	R	X	R	X	
Utility	0.00045	0.00999	0.00045	0.00999	(a)
Equiv. #1	0.00766	0.13031	0.00766	0.13031	(b)
Paralleling of the utility (a) with Equiv. #1 (b)	0.00043	0.00928	0.00043	0.00928	(c)
Line	0.00139	0.00296	0.00139	0.00296	(d)
Trans T-2	0.00313	0.05324	0.00313	0.05324	(e)
Add (c), (d), (e)	0.00495	0.06548	0.00495	0.06548	(f)
Generator #2	0.00287	0.10240	0.00287	0.10240	(g)
Equiv. #2	0.00730	0.22314	0.01057	0.33425	(h)
Parallel (f), Gen #2(g) with Equiv. #2 (h)	0.00145	0.03388	0.00155	0.03568	(i)
Cable C-M1	0.00118	0.00098	0.00118	0.00098	(j)
Add (i), (k)	0.00263	0.03486	0.00273	0.03666	(k)
Equiv. #3	999.999	9999.99	999.999	9999.99	(l)
Parallel (k) with Equiv. #3 (l)	0.00263	0.03486	0.00273	0.03666	(m)
Cable C-M2	0.00079	0.00065	0.00079	0.00065	(n)
Trans T-13	0.02289	0.22886	0.02289	0.22886	(o)
Add (m), (n), (o) (total impedance viewed through trans T-13)	0.02631	0.26437	0.02641	0.26617	(p)

Table 5-4—Calculations for fault current via trans T-13

	First cycle	Interrupting	
$I = \text{MVA}_{\text{base}} / (\sqrt{3} \text{ kV} \times Z)$	9.0547 kA at 84.32°	8.9938 kA at 84.33°	at 2.4 kV
	$X/R = 10.05$	$X/R = 10.08$	

5.9 Sample computer printout

In all cases of interest, computer programs are used that automatically provide the impedance corrections for interrupting time calculations. A small sample of the results for the example one-line (and system data) from Chapter 4 are given here for illustrative purposes. As was the case in the examples in Chapter 4, the numerical values given here are only intended to offer an idea of what is available from numerous commercially-available short-circuit programs. Because different programs will make slightly different modeling assumptions, particularly for data that is not available as input from the user, the results given here should not be used for benchmarking purposes.

First cycle

```
* BUS: 36:T13 SEC *****
      9.053 KA AT -84.24 DEG ( 37.63 MVA): X/R = 10.05 KV = 2.400
      Ze = 0.0266656 +j      0.2643842 (Complex)
      SYM kA*1.6 = 14.48      ASYM kA Based on X/R ratio = 13.08 kA
```

CONTRIBUTIONS TO FAULT:

BUS	to	BUS	MAG	ANG
31:FDR P		36:T13 SEC	9.053	-84.24

Interrupting time

```
* BUS: 36:T13 SEC *****
      8.992 KA AT -84.25 DEG ( 37.38 MVA): X/R = 10.08 KV = 2.400
      Ze = 0.0267965 +j      0.2661861 (Complex)
```

CONTRIBUTIONS TO FAULT:

BUS	to	BUS	MAG	ANG
31:FDR P		36:T13 SE	8.992	-84.25

5.10 Sample computer printout for larger system calculations

The computer printout following is for selected buses and shows the effects of the synchronous machines on the fault levels. The input listing can be found in Chapter 4. Because the decaying ac sources are present, the first cycle and interrupting time fault currents will differ. These results are provided for illustrative purposes only and should not be used for benchmarking purposes.

First cycle

```
***** BUS:100 :UTIL-69 *****
      9.669 KA AT -87.34 DEG (1155.60 MVA): X/R = 21.65 KV = 69.000
      Ze = 0.0004015 +j      0.0086442 (Complex)
      SYM kA*1.6 = 15.47      ASYM kA Based on X/R ratio = 15.30 kA
```

CONTRIBUTIONS TO FAULT:

BUS	to	BUS	MAG	ANG	BUS	to	BUS	MAG	ANG
UTIL		100 :UTIL	8.367	-87.42	01:69-1		100 :UTIL	0.641	-86.63
02:69-2		100 :UTIL	0.661	-87.01					

******* BUS:03:MILL-1 *******

```
      12.012 KA AT -86.56 DEG ( 287.11 MVA): X/R = 18.10 KV = 13.800
      Ze = 0.0020875 +j      0.0347668 (Complex)
      SYM kA*1.6 = 19.22      ASYM kA Based on X/R ratio = 18.70 kA
```

CONTRIBUTIONS TO FAULT:

BUS	to	BUS	MAG	ANG	BUS	to	BUS	MAG	ANG
01:69-1		03:MILL-1	6.373	-85.68	03:MILL-1		09:FDR E	-0.001	0.04
03:MILL-1		05:FDR F	0.000	0.00	03:MILL-1		26:FDR G	0.000	0.00
03:MILL-1		06:FDR H	0.000	0.00	03:MILL-1		50:GEN1	-5.640	-87.57

******* BUS:04:MILL-2 *******

12.326 KA AT -86.95 DEG (294.62 MVA): X/R = 23.29 KV = 13.800
Ze = 0.0018056 +j 0.0338942 (Complex)
SYM kA*1.6 = 19.72 ASYM kA Based on X/R ratio = 19.63 kA

CONTRIBUTIONS TO FAULT:

BUS to BUS	MAG	ANG	BUS to BUS	MAG	ANG
GEN 04:MILL-2	4.084	-88.39	02:69-2 04:MILL-2	6.371	-85.68
04:MILL-2 15:FDR I	0.000	0.00	04:MILL-2 16:T9 PRI	0.000	0.00
04:MILL-2 08:FDR L	-1.874	-88.13	04:MILL-2 24:FDR M	0.000	0.00
04:MILL-2 27:T12 PRI	0.000	0.00			

***** BUS:17:T5 SEC *****

24.723 KA AT -81.44 DEG (20.55 MVA): X/R = 6.66 KV = 0.480
Ze = 0.0723980 +j 0.4811063 (Complex)
SYM kA*1.6 = 39.56 ASYM kA Based on X/R ratio = 33.26 kA

CONTRIBUTIONS TO FAULT:

BUS to BUS	MAG	ANG	BUS to BUS	MAG	ANG
12:T5 PRI 17:T5 SEC	24.723	-81.44	17:T5 SEC 22:T5MCC	0.000	0.00

Interrupting time

***** BUS:100 :UTIL-69 *****

9.629 KA AT -87.35 DEG (1150.80 MVA): X/R = 21.70 KV = 69.000
Ze = 0.0004020 +j 0.0086803 (Complex)

CONTRIBUTIONS TO FAULT:

BUS to BUS	MAG	ANG	BUS to BUS	MAG	ANG
UTIL 100 :UTIL	8.367	-87.42	01:69-1 100 :UTIL	0.641	-86.63
02:69-2 100 :UTIL	0.621	-87.11			

***** BUS:03:MILL-1 *****

12.008 KA AT -86.57 DEG (287.02 MVA): X/R = 18.11 KV = 13.800
Ze = 0.0020873 +j 0.0347785 (Complex)

CONTRIBUTIONS TO FAULT:

BUS to BUS	MAG	ANG	BUS to BUS	MAG	ANG
01:69-1 03:MILL-1	6.369	-85.68	03:MILL-1 09:FDR E	-0.001	-0.55
03:MILL-1 05:FDR F	0.000	0.00	03:MILL-1 26:FDR G	0.000	0.00
03:MILL-1 06:FDR H	0.000	0.00	03:MILL-1 50:GEN1	-5.640	-87.57

***** BUS:04:MILL-2 *****

11.703 KA AT -86.89 DEG (279.73 MVA): X/R = 23.02 KV = 13.800
Ze = 0.0019365 +j 0.0356961 (Complex)

CONTRIBUTIONS TO FAULT:

BUS to BUS	MAG	ANG	BUS to BUS	MAG	ANG
GEN 04:MILL-2	4.084	-88.39	02:69-2 04:MILL-2	6.371	-85.68
04:MILL-2 15:FDR I	0.000	0.00	04:MILL-2 16:T9 PRI	0.000	0.00
04:MILL-2 08:FDR L	-1.251	-88.19	04:MILL-2 24:FDR M	0.000	0.00
04:MILL-2 27:T12 PRI	0.000	0.00			

***** BUS:17:T5 SEC *****

24.722 KA AT -81.44 DEG (20.55 MVA): X/R = 6.66 KV = 0.480
Ze = 0.0723978 +j 0.4811180 (Complex)

CONTRIBUTIONS TO FAULT:

```

BUS to BUS      MAG      ANG      BUS to BUS      MAG      ANG
12:T5 PRI 17:T5 SEC 24.722  81.44  17:T5 SEC 22:T5MCC 0.000  0.00

***** BUS:19:T7 SEC *****
13.181 KA AT -85.15 DEG ( 54.79 MVA); X/R = 11.92 KV = 2.400
Ze = 0.0154229 +j 0.1818492 (Complex)

CONTRIBUTIONS TO FAULT:
BUS to BUS      MAG      ANG

```

5.11 Conclusions

In this chapter, the techniques necessary for incorporating the effects of ac decay due to synchronous machines have been presented. Through the use of simple reactance multipliers, a straightforward extension of the basic calculation techniques of previous chapters can be made to account for reduced fault currents supplied by synchronous machines during time periods beyond the first cycle. The reactance modifiers presented here are consistent with those in other relevant standards and provide conservative results. The calculation approach has been demonstrated through “hand” calculations, and sample computer results have been presented that show the capabilities of modern commercial programs.

5.12 Bibliography

- [B1] ANSI/NEMA Std Pub. No. MG1-2003, Motors and Generators, paragraph MG1-1.58.^{2, 3}
- [B2] IEC 909:1977, German National Committee Report No. 73: Short-Circuit Currents.⁴
- [B3] IEEE Std C37.010-1999 (Reaff 2005), IEEE Application Guide for AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis.^{5, 6}
- [B4] IEEE Std C37.13-1990 (Reaff 1995), IEEE Standard for Low-Voltage AC Power Circuit Breakers Used on Enclosures.

²ANSI publications are available from the Sales Department, American National Standards Institute, 25 West 43rd Street, 4th Floor, New York, NY 10036, USA (<http://www.ansi.org/>).

³NEMA publications are available from Global Engineering Documents, 15 Inverness Way East, Englewood, Colorado 80112, USA (<http://global.ihs.com/>).

⁴IEC publications are available from the Sales Department of the International Electrotechnical Commission, Case Postale 131, 3, rue de Varembe, CH-1211, Genève 20, Switzerland/Suisse (<http://www.iec.ch/>). IEC publications are also available in the United States from the Sales Department, American National Standards Institute, 11 West 42nd Street, 13th Floor, New York, NY 10036, USA.

⁵IEEE publications are available from the Institute of Electrical and Electronics Engineers, 445 Hoes Lane, P.O. Box 1331, Piscataway, NJ 08855-1331, USA (<http://standards.ieee.org/>).

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Chapter 6

Calculating ac short-circuit currents for systems with contributions from induction motors

6.1 Introduction

This chapter describes the calculations of three-phase short-circuit currents for systems with ac current decay from induction motors. This could be applicable to many commercial and industrial systems.

This chapter is limited to the consideration of short-circuit currents that occur under the following conditions:

- 1) Short-circuit fault currents that occur in low-voltage ac systems and medium-voltage ac systems operating at a constant frequency.
- 2) For the duration of the short circuit, there is no change in the source driving voltage or voltages that caused the initial short-circuit current to flow.
- 3) The fault impedance is zero and has no current limiting effect.
- 4) Motor fault current contribution varies with time after the fault and is not negligible.
- 5) For simplification, only three-phase faults will be considered. Unbalanced faults are covered in Chapter 11.

6.2 Purpose

The objective of this chapter is to give recommended standardized procedures for the calculation of short-circuit current on systems with ac decay from induction motors. The application and selection of interrupting equipment based on the calculated fault current are covered in Chapter 10. Fault currents with no ac fault current decay are covered in Chapter 4 and fault currents from synchronous machines is covered in Chapter 5. AC current decay calculations add a small amount of complexity to the no ac decay fault calculations. The sample one-line diagram used to show the calculations is the same as used for the previous calculations. Hand and computer generated calculations will be made at several locations.

6.3 ANSI guidelines

The motor reactances used in this chapter will be based on the ratio of interrupting to first cycle reactances as given in IEEE Std C37.010™-1999 [B4],¹ IEEE Std C37.13™-1990 [B5], and an IEEE paper on induction motor contribution (Heuning [B2]). The representation of induction motors by a varying reactance is easily adapted to other analytical techniques, such as IEC 909:1988 [B3].

¹The numbers in brackets correspond to those of the bibliography in 6.13.

IEEE Std C37.010-1999 [B4] includes three conditions, in addition to the condition listed in section 6.1, to be used when calculating fault currents. These are as follows:

- 1) The pre-fault bus voltage is 1.0 p.u.
- 2) Separate resistance and reactance networks are to be used to determine the fault point X/R ratio. This X_{sep}/R_{sep} ratio is to be used to calculate the total asymmetrical fault current. Option: Z/R_{sep} can be considered the same as X_{sep}/R_{sep} .
- 3) Load currents are much smaller than the fault current and neglected.

In IEEE Std C37.010-1999 [B4], several simplified methods are listed for use where the current determined by an E/X calculation (instead of E/Z) meets specific fault current or X/R ratio criteria. For example, when the fault current is less than 80% of the breaker duty, an E/X calculation can be used. To determine if the current calculated by the simplified methods meets these criteria, most of the effort that is needed for the detailed ANSI calculation is already done. Because having several methods to calculate breaker duty current could lead to confusion, the detailed ANSI calculation will be used here. Most computer programs that follow the ANSI recommended method use the more detailed ANSI procedure.

When induction motors are included in a system, the symmetrical ac component of the short-circuit current varies based on the time after the fault. In Chapter 3, asymmetry was discussed and was shown to depend on the fault point X/R ratio and the point on the voltage sine wave at which the fault is initiated. A fault current flowing from energy sources may be asymmetrical and have both an ac and dc component. The dc component is a transient value and decays with time. In Chapter 2, several different theoretical and empirical equations were given that relate the maximum peak and rms currents in the first cycle to the ac symmetrical current. For the sample calculations in this chapter, the “Violet Book” equations will be used and are repeated below.

The first cycle Violet Book equation is:

$$I_{\text{peak}} = I_{\text{ac, peak}} \left(1 + e^{-\frac{4\pi\tau R}{X}} \right) \quad (6.1)$$

$$I_{\text{rms}} = \sqrt{I_{\text{ac, rms}}^2 + I_{\text{dc}}^2} = I_{\text{ac, rms}} \sqrt{1 + 2e^{-\frac{4\pi\tau R}{X}}} \quad (6.2)$$

where $\tau = 0.49 - 0.1e^{-(X/R)/3}$

Equation (2.3) can be rewritten to calculate the total current at other points in time.

$$I_{\text{rms}} = I_{\text{ac, rms}} \sqrt{1 + 2e^{-\frac{4\pi t R}{2X}}} \quad (6.3)$$

where t is in cycles at 60 Hz.

Equation (6.1) and Equation (6.2) can be used to calculate the maximum asymmetry during the first cycle, while Equation (6.3) can be used for interrupting times greater than 1 cycle.

Peak currents are often associated with equipment rated less than 1000 V and rms currents are used with the higher voltage equipment. See the tables in Chapter 2 for the comparison of the approximation equation peaks to the actual peak. When equipment operating times are given in cycles at a particular frequency, the time frequencies can be ratioed to 60 Hz. Five cycles at 50 Hz is the same time as six cycles at 60 Hz.

The dc current decrement for a simple single circuit of one branch is an exponential decay. In a multi-branch power system, a single X/R ratio is only an approximation. Each branch will actually have its own time constant and the total current will decay at some rate that is dependent on the combined effect. There is no single time constant that will exactly describe the dc decrement of a multi-branch total fault current.

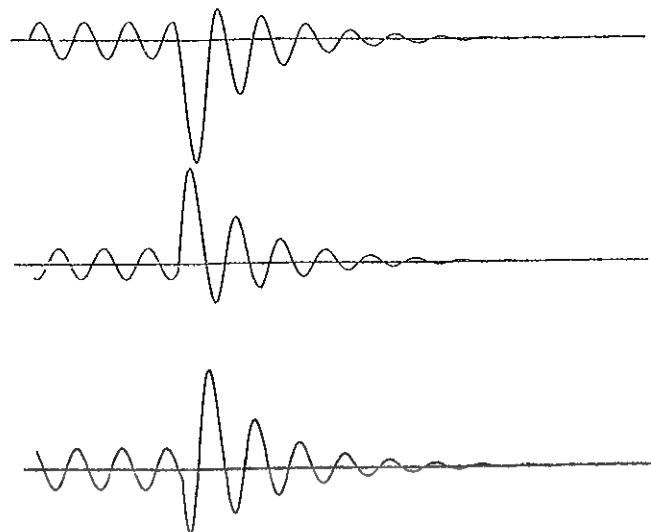
6.4 Fault calculations

Fault calculations can be done in per-unit or in ohms with transformer ratios taken into account. The sample calculations used in this book will be shown using the per-unit method. The steps in calculating ANSI fault currents are as follows:

- 1) Obtain an up-to-date one-line diagram.
- 2) Determine the impedance of each branch and source for the time period of concern.
- 3) Reduce the network impedances to a single R and X using separate R and X network reductions.
- 4) *Optional:* Reduce the network impedances to a single R and X impedance using separate R and complex impedance network reductions and calculate equivalent X/R from Z/R_{sep} .
- 5) Calculate the fault current by combining the separate R and X fault point impedance and treating the result as a complex impedance or by using the optional complex impedance network impedance.
- 6) Calculate the fault point X/R ratio using the separate R and X network reduction values.
- 7) Calculate any asymmetry currents, if required.
- 8) Calculate the branch contributions, if required.

6.5 Nature of induction motor contributions

A running induction motor that has a bolted three-phase short circuit suddenly connected across its terminals will contribute currents to the short circuit. Typical fault current vs. time plots are shown in Figure 6-1. The plot shows a high initial current decay followed by fairly rapid decay to zero.



**Figure 6-1—Three-phase short-circuit currents from an induction motor
(vertical axis represents current; horizontal axis represents time)**

The current contribution is caused by a stator driving voltage generated by trapped rotor flux. The current to the terminal short circuit is limited by the internal reactance of the motor. The current in two or all three phases is asymmetrical at first, and that each offset current consists of an ac and a dc component. The ac component decays because the rotor flux is not maintained by normal applied voltage. The dc component, a transient not supported by any driving voltage, also decays. The frequency differs initially from system frequency by motor slip and thereafter reduces at a rate dependent on motor mechanical load and combined motor and load inertia. For the first few cycles after the short circuit, the frequency change is usually conservatively considered to be inconsequential.

The initial magnitude of the ac component is calculated using the subtransient motor reactance X'' . It is accepted practice to substitute the known or estimated locked rotor reactance X_{LR} for X'' . The initial magnitude of dc component for short-circuit calculations is taken to be equal to the crest value of the initial ac component. This is based on the conservative assumption that the current in one of the phases will have the maximum possible asymmetry.

The equivalent circuit used to represent an induction motor or a group of induction motors with similar characteristics in simplified short-circuit calculations is shown in Figure 6-2. For calculations based on Thevenin's theorem, the equivalent circuit of the complete system uses a single induction motor reactance that represents motors of different decays. The individual induction motor voltage sources disappear by incorporation into the Thevenin equivalent single driving voltage. For a fault calculation involving different times after the fault, a different equivalent motor reactance would result because induction motor equivalent reactances vary considerably with the motor size and speed.

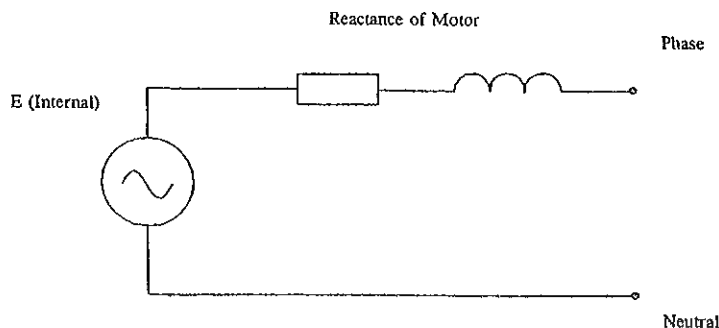


Figure 6-2—Induction motor per phase equivalent circuit

As indicated earlier, the ac component fault current from an induction motor will decay with time. A simplified calculation technique accounts for the ac component current decay by increasing the reactance from X'' in increments as time passes after the short circuit starts. This approach has the advantage of obtaining the correct value of ac fault current while keeping the driving point voltage constant. Keeping the driving point voltage constant simplifies the calculation process by allowing complex power systems to be reduced to a simpler equivalent circuit. This technique is widely used and accepted by the industry. The multipliers used to increase the reactance depend on the induction motor horsepower, motor type and speed. Table 6-2 provides the recommended multipliers.

Short circuits are calculated frequently for fault points separated from contributing induction motor terminals by series impedances. For simplified calculations, the same reactance multiplying factors are applied to motor reactances whether the fault point is close to, or remote from, the motor terminals. This is ideal for simplifying short-circuit studies of large systems, usually performed by computer, because the set of equivalent circuit impedances does not change as the fault point is relocated to calculate duties for many buses.

In actual power systems, the voltage at a motor during a remote short circuit may be partially sustained by nearer power sources. Initially, the voltage is depressed by the fault and the motor generates a short-circuit current contribution. During the fault any partially sustained voltage, if high enough, returns the motor to normal motoring function at less than normal voltage. The simplified short-circuit calculation methods ignore this effect and assume that all connected medium and large size motors, no matter how remote, continue to contribute current to short circuits for at least four cycles after the short circuit starts. However, due to this network action and a higher total equivalent impedance between the remote motors and the fault, the remote motors contribution is less than it would be for a terminal fault.

The reactance multiplying factors that increase with time account for partial decay but not possibly complete disappearance of the motor contribution.

For longer times after the short circuit, appreciably after four cycles, smaller induction motors are usually omitted from the equivalent circuit because induction motor fault current contribution decay is rapid and approaching zero although the motors remain connected. In addition, some motors nearer the fault may have been disconnected by relays or contactor dropout on depressed voltage due to the nearby fault. The motor drop-out effect could be included in interrupting time calculations. However, for a conservative short-circuit current, often it is assumed that the motors do not drop out.

6.6 Large induction motors with prolonged contributions

When one or several large induction motors might appreciably affect the total short-circuit current at a given bus, better accuracy is obtained by calculating motor current at particular times of interest after the short circuit starts (for example, at first cycle and at contact-parting times for medium-voltage circuit breakers). ANSI-approved guides for ac medium-voltage circuit breakers suggest this in a note to the rotating machine reactance table.

Both ac and dc components of motor current (I_{ac} and I_{dc}) are evaluated as time variables assuming the decays from initial magnitudes are exponential, using Equation (6.4) and Equation (6.5):

$$I_{ac} = \left(\frac{E}{Z''}\right) e^{-\frac{2\pi t}{T_d''}} \quad (6.4)$$

and

$$I_{dc} = \sqrt{2} \left(\frac{E}{Z''}\right) e^{-\frac{2\pi t}{T_a}} \quad (6.5)$$

Time t is in cycles at system frequency, and T_d'' and T_a are the frequently used “ X/R ratio” time constants in radians at the same frequency. The time constant in radians for the ac component decay T_d'' is X''/R_R where R_R is the rotor resistance (perhaps modified slightly), and the time constant in radians for the dc component decay T_a is X''/R_S where R_S is the stator resistance (again perhaps modified slightly).

The specified value of T_a is the same as the “ X/R ratio” used in ANSI-approved standard calculations of short-circuit duties for ac high-voltage circuit breakers.

Note that the tangent of the locked rotor impedance angle is less than, and does not substitute for, the ANSI “ X/R ratio.” The locked rotor impedance has more resistance than the resistance used for short-circuit calculations. By definition, R_S is the resistance determining the time constant of the dc component decay. Since the motor dc component currents are varying transiently, this is not the simple dc resistance that applies to the decaying dc currents and the stator ac resistance is often used as a conservative approximation.

Many motor manufacturers are able to provide T_d'' and T_a values for specific important motors, determined according to definitions in ANSI/NEMA Std MG1-1.58 [B1].

For more accurate calculations assuming exponential variations, moving the fault from the motor terminals to insert external impedance in series with the motor reactance affects both the short-circuit current initial magnitude and the time constants. For a series external impedance $Z_e = R_e + jX_e$, current magnitudes are found by substitution $(Z'' + Z_e)$ for Z'' , the ac time constant T_d becomes $(X'' + X_e)/R_R$ and the dc time constant becomes $(X'' + X_e)/(R_S + R_e)$.

When the external circuit from the motor to the fault is more complicated than a single impedance in series with the motor, calculations as just described are usually impractical and simplified calculations are normally used. The simplified calculations are, however, sometimes modified as suggested in ANSI-approved guides. For each large motor with a significant short-circuit contribution, and for each desired specific calculation time t_s after the short-circuit starts, it is suggested that a special reactance multiplying factor be used in simplified calculations for the motor instead of the standard factor listed in Table 6-1. The special reactance factor suggested is $e^{+t_s/T_d''}$, with t_s and T_d'' both in the same time units (same as the reciprocal of $e^{-2\pi t_s/T_d''}$ used for current, with t_s in cycles and T_d'' in radians, same frequency).

For a particularly important bus with large induction motors, combining simplified and more accurate procedures improves the quality of the results. With the motors omitted, the simplified calculation determines the contribution of the rest of the system to the bus short-circuit duty. The motor contribution is separately calculated by the more accurate procedure. Then the ac and dc components of the contributions are separately added and combined to obtain the final result.

6.7 Data accuracy

Data accuracy requirements are a function of motor size. The best possible data should be sought for larger motors that have the highest influence on short-circuit study results. For small motor groups, using first cycle $Z'' = 0.28$ per-unit impedance as typical is probably sufficiently conservative. Individual representation of large and medium motors (or separate groups of medium motors) is normally justified and using manufacturers' locked rotor current data when the actual short-circuit impedance is not known. Whenever it is possible to determine actual initial Z'' before applying multipliers increases confidence in calculation results. When induction motor contributions are especially important and the more accurate exponential calculation is justified, so is the collection of the best possible motor impedance and time constant data.

6.8 Details of induction motor contribution calculations according to ANSI-approved standard application guides

For application of ac medium-voltage circuit breakers, symmetrical (ac component) short-circuit current duties are calculated according to IEEE Std C37.010-1999 [B4], using the

reactance multiplying factors of Table 6-1, column 2. The calculations omit all motors of less than 50 hp each.

For first cycle (momentary) duties to be compared with closing and latching capabilities, subtransient reactance X'' of “medium” motors are multiplied by 1.2 to approximate a somewhat significant decay of the ac component during the first cycle of the short circuit. For “large” motors, the multiplier is 1.0, suggesting no appreciable decay. For symmetrical interrupting duty calculations, reactances of medium and large motors are multiplied, respectively, by 3.0 and 1.5, approximating a greater ac decay at ac medium-voltage circuit breaker minimum contact parting times of 1.5–4 cycles at 60 Hz. The pattern of approximation using these multipliers is illustrated by the solid lines of Figure 6-3.

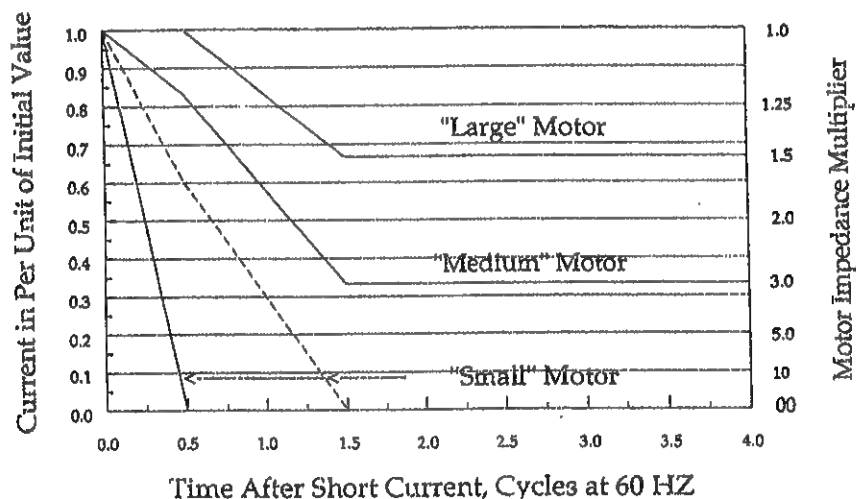


Figure 6-3—Symmetrical rms current contributed by an induction motor to a three-phase short circuit at its terminals; solid lines according to IEEE Std C37.010-1999 [B4]; dotted line suggested by IEEE Std C37.13-1990 [B5]

For application of ac low-voltage power circuit breakers and both medium and low-voltage fuses, only first cycle calculations are necessary, and IEEE Std C37.13-1990 [B5], IEEE Std C37.41-2000 [B6], and ANSI/IEEE C97.1-1972 [B1] recommend representing all rotating machines in the equivalent circuit based on subtransient reactances regardless of motor rated horsepower. IEEE Std C37.13-1990 [B5] qualifies this by suggesting that motor short-circuit current contributions, for “typical” groups of low-voltage motors lacking detailed information, may be estimated at four times the summation of motor rated currents. A contribution of four times rated current corresponds to a first cycle motor $Z = (V/4) = 0.25$ per-unit based on motor rated apparent power (kVA) and voltage of 1 p.u. Usually exact motor short-circuit reactances are not readily available and is approximated by using $1/(\text{locked rotor current})$.

The “four times rated current” approximate short-circuit contribution is determined by assuming a “typical” connected group having 75 percent induction motors at 3.6 times rated current and 25 percent synchronous motors at 4.8 times rated. Other “typical” group assumptions can be made; for example, many groups now have larger low-voltage induction motors instead of synchronous motors, but these larger motors also have higher and longer lasting short-circuit contributions. Accordingly, a “four times rated current” approximation continues to be accepted practice when all load is induction motors of unspecified sizes.

In general, 3.6, 4, or 4.8 times rated current is less than locked rotor current, so this approximation accounts for a sometimes appreciable reduction of ac motor contribution from the initial subtransient value (at $t = 0$) to the first cycle value (evaluated at the half-cycle point) for a fault at the motor terminals. This reduction might be partly explained by the motor cables and/or overload heater impedances in series with low-voltage motors that are often omitted from the calculation, but a very important factor is the decay during the first cycle of motor current contribution due to collapsing motor flux.

6.9 Recommended practice based on ANSI-approved standards for representing induction motors in multivoltage system studies

The differences in the two standards require two first cycle calculations and an interrupting calculation. The ideal representation for multivoltage systems is the simplest that determines with reasonable conservatism the influences of both low- and high-voltage induction motors on short-circuit duties for circuit breakers and fuses at both low and high voltages. A simple first cycle network combining the two similar but different networks of IEEE Std C37.13-1990 [B5] and IEEE Std C37.010-1999 [B4] fits this ideal. The following interpretation and redefinition, based on extending existing similarities, resolves the differences and obtains a single network. Table 6-1 and Table 6-2 provide the multiplying factors and suggested motor reactances to be used when actual data is not available.

For a typical induction motor, the subtransient reactance of 16.7% is determined by the initial magnitude of symmetrical root-mean-square (rms) current contributed to a terminal short circuit, assumed to be six times rated. Using a “4.8 times rated current” first cycle estimate for larger size low-voltage induction motors, described as “medium 50 hp, etc.” in Table 6-1 and Table 6-2, is effectively the same as multiplying the subtransient reactance by approximately 1.2 ($6.0/4.8 = 1.25$). For this motor group, there is reasonable correspondence of low- and medium-voltage calculation procedures.

For smaller induction motors, “small < 50 hp” in Table 6-1 and Table 6-2, a conservative estimate is the “3.6 times rated current” (equivalent of 0.28 per-unit reactance) first cycle assumption of low-voltage standards, and this is effectively the same as multiplying 16.7% subtransient reactance by 1.67.

With this interpretation as a basis, the recommended “small” low-voltage induction motor representation is shown by Table 6-2, column 4, and by a dotted line on Figure 6-3. The entries for medium-size motors are the same as in Table 6-1 for medium-voltage

calculations, and their use adds conservatism to low-voltage calculations when many induction motors are not “small.” The entries for small-size motors are essentially the same as in IEEE Std C37.13 [B5] for low-voltage calculations, and their use adds some conservatism to medium-voltage first cycle calculations without changing interrupting duty calculations. Column 4 of Table 6-1 provides the recommended reactance multipliers that bridge the two ANSI-approved standards.

More high-efficiency motors are being used in industrial system, which have higher locked-rotor currents and therefore lower subtransient reactances. Some engineering judgment must be used in the selection of assumed motor reactances based on the types of motors being used.

Table 6-1—Induction motor reactance multiplying factor from IEEE Std C37.010 [B4] and IEEE Std C37.13 [B5] using $X'' = 16.7\%$ ^a

	Medium voltage and high voltage per IEEE Std C37.010	Low voltage per IEEE Std C37.13	Recommended reactance multiplier
First cycle calculations			
Large induction motors			
> 1000 HP or	16.7%	27.8%	16.7%
> 250 HP and 2 pole			
Medium induction motors			
50 to 249 HP or	20.0%	27.8%	20.0%
250 to 1000 HP > 2 pole			
Small induction motors	×	27.8%	27.8%
< 50 HP			
Interrupting time calculations (3–5 cycles)			
Large induction motors			
> 1000 HP or	25.0%	^b	25.0%
> 250 HP and 2 pole			
Medium induction motors			
50 to 249 HP or	50.0%	^b	50.0%
250 to 1000 HP > 2 pole			
Small induction motors			
< 50 HP	×	^b	×

^a X''_{lr} can be used for X'' .

^b3–5 cycle interrupting times does not apply to low-voltage breakers.

**Table 6-2—Suggested induction motor reactances from
IEEE Std C37.010 [B4] and IEEE Std C37.13 [B5]**

Type of machine	Medium voltage and high voltage per IEEE Std C37.010	Low voltage per IEEE Std C37.13	Recommended reactance multiplier
First cycle calculations			
Large induction motors			
> 1000 HP or	16.7%	27.8%	16.7%
> 250 HP and 2 pole			
Medium induction motors			
50 to 249 HP or	20.0%	27.8%	20.0%
250 to 1000 HP > 2 pole			
Small induction motors	×	27.8%	27.8%
< 50 HP			
Interrupting Time calculations (3–5 cycles)			
Large induction motors			
> 1000 HP or	25.0%	^a	25.0%
> 250 HP and 2 pole			
Medium induction motors			
50 to 249 HP or	50.0%	^a	50.0%
250 to 1000 HP > 2 pole			
Small induction motors			
< 50 HP	×	^a	×

^a3–5 cycle interrupting times does not apply to low-voltage breakers.

6.10 One-line diagram data

The raw data, per-unit data, and one-line used is given in Chapter 4. The one-line diagram from this chapter adds all induction motors and places two generators, buses 04:MILL-2 and 50:GEN1, and a large synchronous motor, bus 08:M-FDR-L out-of-service. The induction motors are the decaying ac fault sources along with the non-decaying utility source and provide current to a faulted bus.

6.11 Sample calculations

6.11.1 Sample calculation #1

For a fault on 2.4 kV bus 36:T13 SEC, the total impedance to the fault is the reduction of all circuit and source impedances to the fault point. The total fault impedance is affected by the motors connected to MILL-1 and MILL-2 buses. This reduces the effective impedance between the utility and MILL-2 bus and increases the fault level at bus 36:T13 SEC. The equivalent motor source impedance is provided on the reduced one-line diagram. The actual series and parallel network reduction to obtain the equivalents is not shown. The calculations for the fault current on bus 36:T13 given below. The manual calculations provide the current magnitudes using separate R and X network reductions while the computer printout uses the complex network reduction for current and separate R and X network reductions for the X/R ratio. The slight differences between the hand calculation and computer calculation for fault current are due to the complex network impedance reduction used in the program as compared to separate R and X reductions used in the hand calculations. The fault point X/R ratio is the same because it is calculated from separate R and X in both cases.

In a system with sources that have a decaying ac component, both a first cycle and interrupting time calculations are required for the high-voltage buses. The source impedances of the connecting buses also require a first cycle and interrupting time equivalent source impedances as shown on Figure 6-4.

The symmetrical fault current via Trans T-13 is shown in Table 6-4.

Table 6-3— R and X per-unit calculations for first cycle and interrupting time

	First cycle		Interrupting time		
	R	X	R	X	
Utility	0.00045	0.00999	0.00045	0.00999	(a)
Equiv. #1	0.02508	0.26190	0.03952	0.50557	(b)
Paralleling of the utility (a) with Equiv. #1 (b)	0.00044	0.00962	0.00044	0.00980	(c)
Line	0.00139	0.00296	0.00139	0.00296	(d)
Trans T-2	0.00313	0.05324	0.00313	0.05324	(e)
Add (c), (d), (e)	0.00496	0.06582	0.00496	0.06600	(f)
Generator #2	—	—	—	—	(g)
Equiv. #2	0.04243	0.51636	0.06225	0.98493	(h)

Table 6-3— R and X per-unit calculations for first cycle and interrupting time (continued)

	First cycle		Interrupting time		
	R	X	R	X	
Parallel (f), Gen #2(g) with Equiv. #2 (h)	0.00444	0.05838	0.00460	0.06186	(i)
Cable C-M1	0.00118	0.00098	0.00118	0.00098	(j)
Add (i), (k)	0.00562	0.05936	0.00578	0.06284	(k)
Equiv. #3	0.35235	2.81283	0.72200	7.94878	(l)
Parallel (k) with Equiv. #3 (l)	0.00553	0.05813	0.00573	0.06234	(m)
Cable C-M2	0.00079	0.00065	0.00079	0.00065	(n)
Trans T-13	0.02289	0.22886	0.02289	0.22886	(o)
Add (m), (n), (o) (total impedance viewed through trans T-13)	0.02921	0.28764	0.02941	0.29185	(p)

Table 6-4—Calculations for fault current via trans T-13

Fault current via Trans T-13			
$I = \text{MVA}_{\text{base}} / (\sqrt{3} \times \text{kV} \times Z)$	8.3204 at -84.20°	8.2011 at -84.24°	at 2.4 kV
	$X/R = 9.84$	$X/R = 9.92$	
Fault current via motor T-13-1 at 2.4 kV			
$I = \text{MVA}_{\text{base}} / (\sqrt{3} \times \text{kV} \times Z)$	2.939 at -88.26°	1.1758 at -88.08°	
Total bus current (vector add)	11.254 at -85.26°	9.374 at -84.73°	
(Based on separate R and X)	$X/R = 15.04$	$X/R = 12.41$	

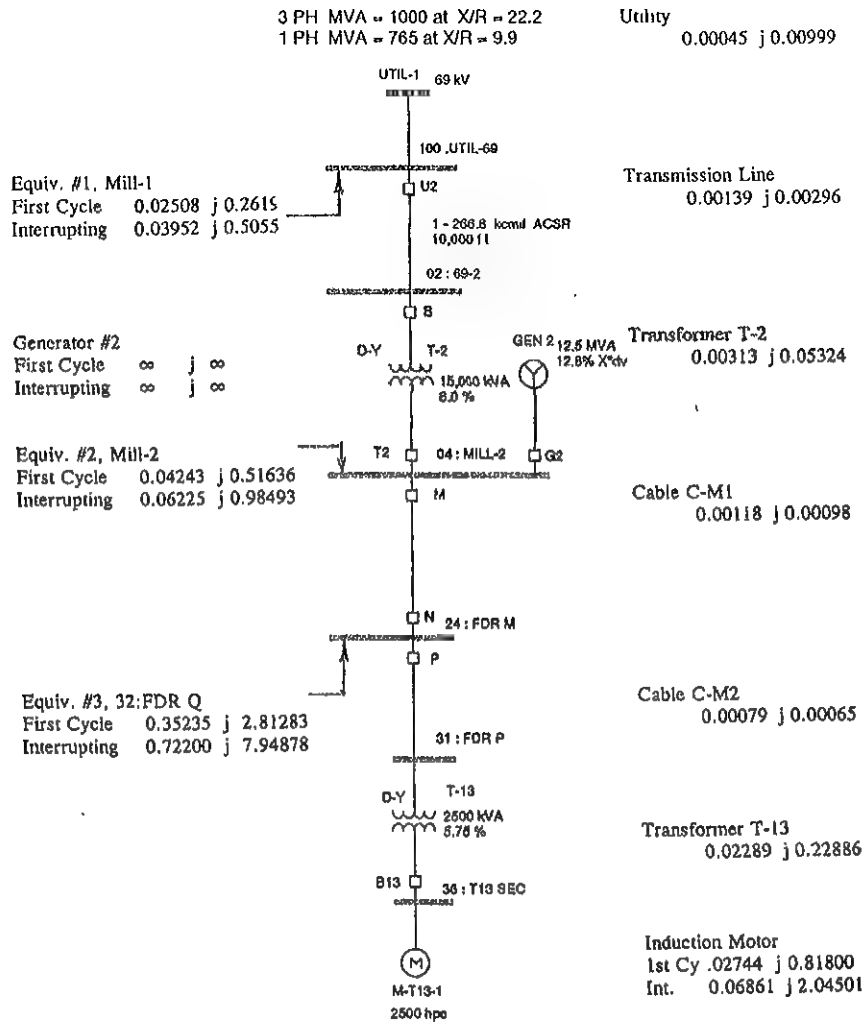


Figure 6-4—Equivalent and impedance one-line diagram for sample calculations

Given below is a sample computer printout for the fault on Bus 36: T13 SEC. There is a slight difference in current due a complex math calculation for the current by the program.

Sample computer printout

First Cycle

```
* BUS: 36:T13 SEC *****
11.254 KA AT -85.21 DEG ( 46.78 MVA): X/R = 15.06 KV = 2.400
Ze = 0.0178490 +j 0.2130016 (Complex)
```

SYM kA*1.6 = 18.01

ASYM kA Based on X/R ratio = 17.18 kA

CONTRIBUTIONS TO FAULT:

BUS to	BUS	MAG	ANG	BUS to	BUS	MAG	ANG
Med Ind	36:T13 SE	2.939	-88.08	31:FDR P	36:T13 SE	8.320	-84.20

Interrupting time

* BUS: 36:T13 SEC *****

9.364 KA AT -84.72 DEG (38.97 MVA): X/R = 12.41 KV = 2.400

Ze = 0.0235982 +j 0.2555270 (Complex)

CONTRIBUTIONS TO FAULT:

BUS to	BUS	MAG	ANG	BUS to	BUS	MAG	ANG
Med Ind	36:T13 SE	1.176	-88.08	31:FDR P	36:T13 SE	8.201	-84.24

Sample calculation #2

Transformer T13 is changed and has a rating of 2.5 MVA, 13.2/2.3 kV, 5.75% impedance, and the selected operating tap is 13.53 kV. Since the transformer voltage rating does not match the 13.8 kV base voltage, three items should be changed, one is the base voltage, the second is the transformer impedance and third is the motor impedance to the new system base voltage. To correct the impedance to the primary 13.8 kV voltage base, Equations (3.11) and Equation (3.12) are used.

$$Z_{\text{Common base}} = Z_{\text{Equip}} \frac{\text{kV}_{\text{Equip base}}^2}{\text{kV}_{\text{Common base}}^2}$$

$$Z_{\text{Common base}} = 5.75 \frac{13.2^2}{13.8^2} = 5.261\%$$

$$Z_{\text{Common base}} = Z_{\text{Equip}} \frac{Z_{\text{Common base}}}{Z_{\text{Equip base}}}$$

$$Z_{10} = 0.05261 \frac{10}{2.5} = 0.02175098 + j 0.21756 \text{ at } X/R = 10.0$$

This value can be entered into some computer programs with the 13.53 kV tap and the transformer impedance will be corrected for tap position. However, for hand calculations or computer programs without transformer tap capabilities, a second step is required to correct for the transformer tap position. The same equation as shown above can be used and the change in transformer calculated in one step. Two steps are shown here for clarity. The transformer T-13 impedance on the 10 MVA system base is:

$$Z_{\text{Common base}} = 0.0217598 + j 0.021756 \frac{13.53^2}{13.2^2} = 0.02200 + j 0.21999$$

The secondary system base voltage is $2.3 \times 13.53/13.2 = 2.3575$.

The 2.4 kV rated motor is corrected to the system base voltage by the same equation as used for the transformer.

$$\begin{aligned}
 Z_{\text{Common base}} &= (0.02744 + j 0.81800) (2.4^2/2.3575^2) \quad (\text{shown with first cycle impedance}) \\
 &= (0.02844 + j 0.84776) \text{ for first cycle} \\
 &= (0.07111 + j 2.11941) \text{ for interrupting time}
 \end{aligned}$$

The network reduction is the same as shown in example #1 up to the point of the cable C-M2 after paralleling equivalent #3 [step (o) in Table 6-5].

The symmetrical fault current via Trans T-13 is shown in Table 6-6.

Table 6-5—R and X per-unit calculations for first cycle and interrupting time

Parallel (k) with Equiv. #3 (l)	0.00553	0.05813	0.00573	0.06234	(m)
Cable C-M2	0.00079	0.00065	0.00079	0.00065	(n)
Trans T-13	0.02200	0.21999	0.02200	0.21999	(o)
Add (m), (n), (o) (total impedance viewed through trans T-13)	0.02832	0.27877	0.02852	0.28298	(p)

Table 6-6—Calculations for fault current via trans T-13

Fault current via Trans T-13			
$I = \text{MVA}_{\text{base}}/(\sqrt{3} \times \text{kV} \times Z)$	8.740 at 84.20° $X/R = 9.84$	8.6107 at 84.24° $X/R = 9.92$	at 2.3575 kV.
Fault current via motor T-13-1 at 2.3575 kV			
$I = \text{MVA}_{\text{base}}/(\sqrt{3} \times \text{kV} \times Z)$	2.887 at -88.26°	1.1549 at -88.26°	
Total bus current (vector add)	11.622 at -85.21°	9.763 at -84.72°	
(Based on separate R and X)	$X/R = 14.92$	$X/R = 12.34$	

6.12 Sample computer printout

The computer printout following is for selected buses to show the more critical buses and to show the effects the induction motors on the fault levels. The input listing can be found in Chapter 4. Because of the decaying ac sources, the first cycle and interrupting time fault currents will differ.

First Cycle

* BUS: 100 :UTIL-69 *****

8.914 KA AT -87.27 DEG (1065.29 MVA) : X/R = 21.65 KV = 69.000
Ze = 0.0004472 +j 0.0093764 (Complex)
SYM kA*1.6 = 14.26 ASYM kA Based on X/R ratio = 14.11 kA

MAX. HIGH VOLTAGE CLF AND POWER FUSE DUTY = 9.25 SYM, = 14.64 ASY
MAX. HIGH VOLTAGE DISTRIBUTION FUSE DUTY = 9.77 SYM, = 15.46 ASY

CONTRIBUTIONS TO FAULT:

BUS to BUS	MAG	ANG	BUS to BUS	MAG	ANG
UTIL 100 :UTIL	8.367	-87.42	01:69-1 100 :UTIL	0.318	-84.53
02:69-2 100 :UTIL	0.229	-85.54			

* BUS: 04:MILL-2 *****

7.691 KA AT -85.66 DEG (183.83 MVA) : X/R = 13.61 KV = 13.800
Ze = 0.0041165 +j 0.0542433 (Complex)
SYM kA*1.6 = 12.31 ASYM kA Based on X/R ratio = 11.60 kA

MAX. HIGH VOLTAGE CLF AND POWER FUSE DUTY = 7.69 SYM, = 11.60 ASY
MAX. HIGH VOLTAGE DISTRIBUTION FUSE DUTY = 8.03 SYM, = 12.11 ASY

CONTRIBUTIONS TO FAULT:

BUS to BUS	MAG	ANG	BUS to BUS	MAG	ANG
02:69-2 04:MILL-2	6.338	-85.68	04:MILL-2 15:FDR I	-0.550	-86.35
04:MILL-2 27:T12 PR	-0.167	-82.49	04:MILL-2 16:T9 PRI	-0.091	-84.11
04:MILL-2 08:FDR L	0.000	0.00	04:MILL-2 24:FDR M	-0.545	-85.95

* BUS: 24:FDR M *****

7.562 KA AT -84.68 DEG (180.76 MVA) : X/R = 11.17 KV = 13.800
Ze = 0.0051256 +j 0.0550855 (Complex)
SYM kA*1.6 = 12.10 ASYM kA Based on X/R ratio = 11.10 kA

MAX. HIGH VOLTAGE CLF AND POWER FUSE DUTY = 7.56 SYM, = 11.10 ASY
MAX. HIGH VOLTAGE DISTRIBUTION FUSE DUTY = 7.69 SYM, = 11.29 ASY

CONTRIBUTIONS TO FAULT:

BUS to BUS	MAG	ANG	BUS to BUS	MAG	ANG
04:MILL-2 24:FDR M	7.016	-84.58	24:FDR M 31:FDR P	-0.399	-87.20
24:FDR M 32:FDR Q	-0.148	-82.86			

* BUS: 31:FDR P *****

7.474 KA AT -84.02 DEG (178.65 MVA) : X/R = 10.02 KV = 13.800
Ze = 0.0058284 +j 0.0556708 (Complex)
SYM kA*1.6 = 11.96 ASYM kA Based on X/R ratio = 10.80 kA

MAX. HIGH VOLTAGE CLF AND POWER FUSE DUTY = 7.47 SYM, = 10.80 ASY
MAX. HIGH VOLTAGE DISTRIBUTION FUSE DUTY = 7.48 SYM, = 10.80 ASY

CONTRIBUTIONS TO FAULT:

BUS to BUS	MAG	ANG	BUS to BUS	MAG	ANG
31:FDR P 36:T13 SE	-0.399	-87.25	24:FDR M 31:FDR P	7.076	-83.84

* BUS: 36:T13 SEC *****

11.254 KA AT -85.21 DEG (46.78 MVA) : X/R = 15.06 KV = 2.400
Ze = 0.0178490 +j 0.2130016 (Complex)

SYM KA*1.6 = 18.01 ASYM KA Based on X/R ratio = 17.18 kA

MAX. HIGH VOLTAGE CLF AND POWER FUSE DUTY = 11.26 SYM, = 17.18 ASY
MAX. HIGH VOLTAGE DISTRIBUTION FUSE DUTY = 11.90 SYM, = 18.16 ASY

CONTRIBUTIONS TO FAULT:

BUS to BUS	MAG	ANG	BUS to BUS	MAG	ANG
Med Ind 36:T13 SE	2.939	-88.08	31:FDR P 36:T13 SE	8.320	-84.20

Interrupting time

* BUS: 100 :UTIL-69 *****

8.654 KA AT -87.37 DEG (1034.21 MVA) : X/R = 21.99 KV = 69.000
Ze = 0.0004440 +j 0.0096591 (Complex)

CONTRIBUTIONS TO FAULT:

BUS to BUS	MAG	ANG	BUS to BUS	MAG	ANG
UTIL 100 :UTIL 8.367		-87.42	01:69-1 100 :UTIL 0.165		-85.33
02:69-2 100 :UTIL 0.121		-86.50			

* BUS: 01:69-1 *****

6.633 KA AT -81.93 DEG (792.74 MVA) : X/R = 7.19 KV = 69.000
Ze = 0.0017702 +j 0.0124897 (Complex)

CONTRIBUTIONS TO FAULT:

BUS to BUS	MAG	ANG	BUS to BUS	MAG	ANG
01:69-1 03:MILL-1 -0.166		-85.46	01:69-1 100 :UTIL -6.467		-81.84

* BUS: 04:MILL-2 *****

6.981 KA AT -85.78 DEG (166.87 MVA) : X/R = 13.78 KV = 13.800
Ze = 0.0044095 +j 0.0597656 (Complex)

CONTRIBUTIONS TO FAULT:

BUS to BUS	MAG	ANG	BUS to BUS	MAG	ANG
02:69-2 04:MILL-2 6.321		-85.69	04:MILL-2 15:FDR I -0.393		-86.48
04:MILL-2 27:T12 PR -0.031		-85.11	04:MILL-2 16:T9 PRI 0.000		0.00
04:MILL-2 08:FDR L 0.000		0.00	04:MILL-2 24:FDR M -0.236		-86.99

* BUS: 24:FDR M *****

6.866 KA AT -84.81 DEG (164.12 MVA) : X/R = 11.28 KV = 13.800
Ze = 0.0055071 +j 0.0606812 (Complex)

CONTRIBUTIONS TO FAULT:

BUS to BUS	MAG	ANG	BUS to BUS	MAG	ANG
04:MILL-2 24:FDR M 6.630		-84.74	24:FDR M 31:FDR P -0.184		-87.68
24:FDR M 32:FDR Q -0.052		-84.81			

* BUS: 31:FDR P *****

6.790 KA AT -84.18 DEG (162.29 MVA) : X/R = 10.10 KV = 13.800
Ze = 0.0062527 +j 0.0612986 (Complex)

CONTRIBUTIONS TO FAULT:

BUS to BUS	MAG	ANG	BUS to BUS	MAG	ANG
31:FDR P 36:T13 SE -0.184		-87.70	24:FDR M 31:FDR P 6.606		-84.08

* BUS: 36:T13 SEC *****

9.374 KA AT -84.72 DEG (38.97 MVA) : X/R = 12.41 KV = 2.400

$$Z_e = 0.0235982 + j 0.2555270 \text{ (Complex)}$$

CONTRIBUTIONS TO FAULT:

BUS to	BUS	MAG	ANG	BUS to	BUS	MAG	ANG
Med Ind	36:T13 SE	1.176	-88.08	31:FDR P	36:T13 SE	8.201	-84.24

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- [B2] Huening, Walter C. Jr., "Calculating Short-Circuit Currents with Contributions from Induction Motors," *IEEE Transactions*, IAS Vol. 1A-18, No. 2, Mar/Apr 1982.
- [B3] IEC 909-1988, International Standard, Short-circuit Current Calculation in Three-phase a.c. Systems, First edition.⁴
- [B4] IEEE Std C37.010-1999 (Reaff 2005), IEEE Application Guide for AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis.^{5, 6}
- [B5] IEEE Std C37.13-1990 (Reaff 1995), IEEE Standard for Low-Voltage AC Power Circuit Breakers Used on Enclosures.
- [B6] IEEE Std C37.41-2000, IEEE Standard Design Tests for Distribution Cutouts and Fuse Links, Secondary Fuses, Distribution Enclosed Single-Pole Air Switches, Power Fuses, Fuse Disconnecting Switches, and Accessories.

²ANSI publications are available from the Sales Department, American National Standards Institute, 25 West 43rd Street, 4th Floor, New York, NY 10036, USA (<http://www.ansi.org/>).

³NEMA publications are available from Global Engineering Documents, 15 Inverness Way East, Englewood, Colorado 80112, USA (<http://global.ihs.com/>).

⁴IEC publications are available from the Sales Department of the International Electrotechnical Commission, Case Postale 131, 3, rue de Varembé, CH-1211, Genève 20, Switzerland/Suisse (<http://www.iec.ch/>). IEC publications are also available in the United States from the Sales Department, American National Standards Institute, 11 West 42nd Street, 13th Floor, New York, NY 10036, USA.

⁵IEEE publications are available from the Institute of Electrical and Electronics Engineers, 445 Hoes Lane, P.O. Box 1331, Piscataway, NJ 08855-1331, USA (<http://standards.ieee.org/>).

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Chapter 7

Capacitor contributions to short-circuit currents

7.1 Introduction

Capacitor discharge currents from power factor correction capacitors or harmonic filters have not previously been considered in the ANSI or IEC calculation procedures. The stresses associated with capacitor discharge currents are different than typical fault conditions due to the high-frequency components present within currents and the extremely fast time constants of the capacitor circuits. These conditions may affect equipment sensitive to high-frequency currents.

This section describes the nature of capacitive discharge currents during fault conditions and the effect of capacitor currents on the total fault current. Guidelines if applicable, will be provided for properly considering and accounting for the fault currents imposed on equipment applied near capacitor banks. Energizing capacitors and back-to-back switching of capacitors is not covered in this chapter.

7.2 Capacitor discharge current

A capacitor in an ac system charges and discharges in a controlled manner every half cycle, based on the sinusoidal driving voltage and system impedances. When a fault occurs, the system voltage is suddenly changed and the capacitor discharges at a rapid rate, with a high discharge current. The current is greatest if the fault occurs when the capacitor is charged to the maximum at a voltage peak. Only the impedance between the capacitor and the fault limits the discharge current. The current will “ring down” based on circuit resistance and reactance. The resistance provides damping and the interaction between the system reactance and capacitor determines the frequency of the oscillating current. The discharge current can be expressed by the Equation (7.1):

$$I_{pk} = \frac{\sqrt{\frac{2}{3}} \times V_{LL} \times e^{-Rt/L} \sin(\omega_0 t)}{Z_0} \quad (7.1)$$

where

V_{LL} = the system line-to-line voltage

L = the inductance between the capacitor bank and the fault

R = the resistance between the capacitor bank and the fault

$$Z_0 = \sqrt{\frac{L}{C}}$$

$$\omega_0 = \frac{1}{\sqrt{LC}}$$

In the above expression, ω_0 is the natural frequency of the oscillatory circuit in radians per second. The natural frequency is often relatively high compared to the system frequency. The maximum peak current from the Equation (7.1) is shown in Equation (7.2) below.

$$I_{\max} = \sqrt{\frac{2}{3}} \times V_{LL} \times \sqrt{\frac{C}{L}} \quad (7.2)$$

Equation (7.2) shows that the worst-case transient fault current depends on the magnitude of the system voltage, the inductance between the capacitor and the fault, and the capacitance of the bank. Thus, an increase in voltage or capacitance increases the discharge current. Since an increase in the inductance decreases the current, the distance from the bank to the fault can be quite significant in determining the discharge current. The magnitude of the discharge current may be negligible for equipment located farther from the capacitor bank.

Equation (7.1) and Equation (7.2) also indicate that both the magnitude and the natural frequency of the discharge current may be relatively high as compared to the magnitude and frequency of the system fault currents, as demonstrated in the following example.

7.2.1 Example

The 10 Mvar capacitor bank shown in Figure 7-1 has the following capacitive reactance and capacitance:

$$X_c = 19.04 \, \Omega$$

$$C = 139.3 \, \mu\text{F}$$

The capacitor bank will draw $|I_c| = 418.4 \text{ A}_{\text{rms}}$ under steady-state rated conditions. The bank is connected to the bus through 30 m of 3-1/C 500 kcmil conductors with the following impedance:

$$Z' = 0.0276 + j0.0520 \, \Omega/300 \text{ m}$$

$$Z = 0.00276 + j0.0052 \, \Omega$$

so

$$R = 0.00276 \, \Omega \text{ and } L = 13.79 \, \mu\text{H}$$

This translates to a peak discharge current of 35.8 kA at a frequency of 3.631 kHz. Note that the frequency of the discharge current is over sixty times the fundamental frequency of the fault current. The time constant of the discharge current is the time for the current in the series RLC circuit to reach 36 percent of its final value. In this case, the time constant is as follows:

$$2T_s = L/2R = 9.99 \text{ ms}$$

which is slightly over 1/2 of a cycle on a 60 Hz system.

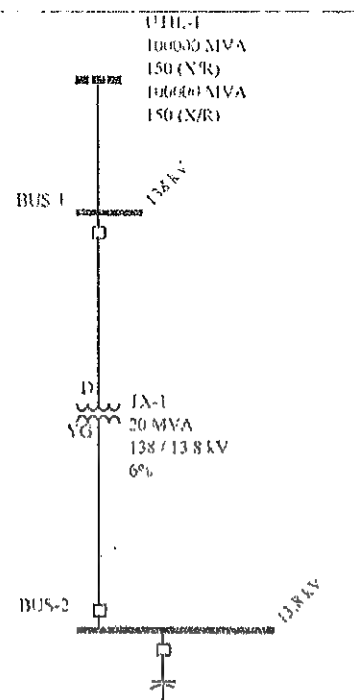


Figure 7-1—One-line diagram for example case

7.3 Transient simulations

To better understand the transient response, several test systems were developed and modeled using time-domain transient simulation software. Use of this type of software allows complete simulation of all types of transient phenomena including the interactions between different circuit elements to a defined disturbance. Modeling guidelines were derived from Greenwood [B1].¹

7.3.1 Standard capacitor bank

The system of Figure 7-1 was modeled to determine the effects of capacitor discharge as a function of capacitor MVA, circuit length, and interaction with the utility source. The example was chosen as a typical industrial supply with realistic circuit parameters similar to field conditions.

A three-phase bolted fault was placed on the 13.8 kV bus 15 ms into the simulation while the system was in steady-state. The faults were initiated at voltage peak in order to maximize the current offset. The initial fault current without capacitors was calculated as

¹The numbers in brackets correspond to those of the bibliography in 7.5.

31 340 amperes (with dc offsets included) based on the impedance looking back to the source.

Figure 7-2 shows the results of a simulation for the case described in the previous example. Plot 7-2(a) shows only the capacitor currents on the phase with the largest current. The plot in Figure 7-2(b) shows the fault current contribution from the source, and plot 7-2(c) shows the total fault current on that phase. Notice that the peak capacitor current matches the predicted current of 35 806 A fairly closely, with a peak current of 36 253 A. The total peak fault current is 43 539 A, which occurs during the first cycle when the current contribution from the source reaches its sinusoidal peak. Of this peak current, the capacitor contributes roughly 25 000 A. Note that the capacitor current decays fairly quickly.

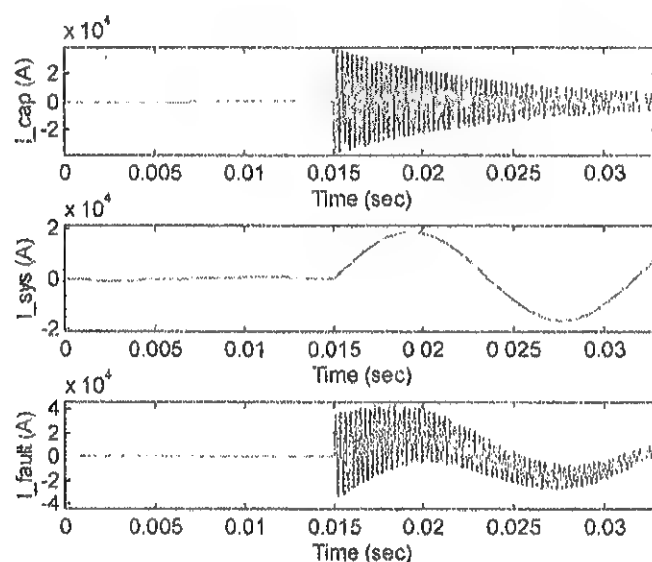


Figure 7-2—Fault study with 10 Mvar capacitor separated from fault by 30 m of cable

Note that the cable model used for these calculations is a fairly simple one. The increased resistance due to skin effect at the natural frequency is not included. The impact of cable capacitance and coupling between phases is also neglected. Including these elements in the model will both increase the magnitude of the initial transient and the speed the decay of the capacitor contribution. Figure 7-3 shows fault current when the cable is modeled first with a single coupled pi section, and second with a distributed parameter traveling wave model (with parameters calculated at 1000 Hz). Both cases have nearly identical maximum currents, but now the peak occurs almost immediately due to the interaction with the cable capacitance. Note also, that the travel times for electromagnetic waves on the 30-meter cable are very short.

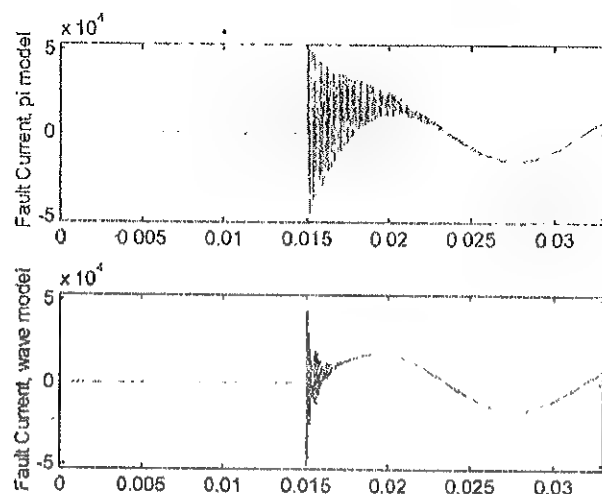


Figure 7-3—Fault currents with coupled-pi and traveling wave models for the 30 m cable and 10 Mvar capacitor bank

Figure 7-4 shows the results of a 10 Mvar capacitor in series with 15 m of 3-1/C-500 kcmil copper conductors. The cable is modeled using a traveling wave model for the cable.

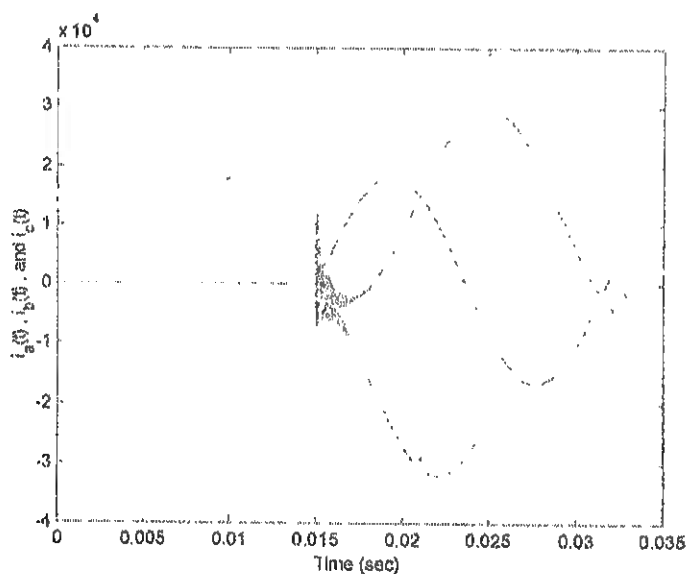


Figure 7-4—Fault current with 15 m cable and 10 Mvar capacitor bank

As can be seen, there is a high initial transient at the onset of the fault that damps quickly down in less than 0.5 ms (1/30 cycle) due to the very short time for the voltage and current waves to traverse the cable between the fault and the capacitor. Nearly complete ring

down occurs in approximately 2.0 ms or 1/8 of a cycle. As can be expected, lower values of capacitance reduce the transient and time constant.

Figure 7-5 shows the same system with 300 m of cable in order to determine the effect of the added cable inductance on the response. Note that the peak fault currents are higher in this case.

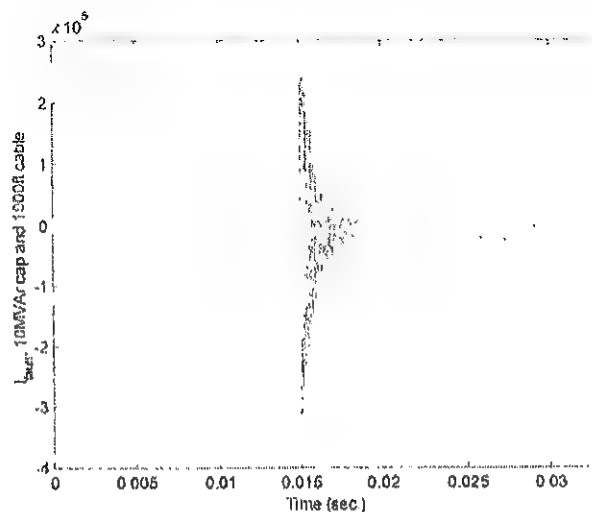


Figure 7-5—Fault current with 300 m cable separating 10 Mvar capacitor from the fault

The initial transient is nearly ten times higher than in the 30 m cable, and takes longer to damp down due to the longer travel times on the longer cable. Complete ring down still occurs in approximately 2.0 ms or 1/8 of a cycle.

Standard capacitor connections show high transient discharge currents that damp quickly before a 1/4 cycle. Low X/R ratio cables associated with industrial installations do not increase the time constant significantly to produce extended transient times, which could affect breaker operation.

During fault conditions, the capacitor discharge takes place in the initial 1/30–1/8 cycles, depending on the time constant of the system. Since the breaker protective device and contacts cannot operate in this time frame, the discharge takes place into closed contacts. The electromagnetically induced forces of the discharge current are instantaneously proportional to the current squared. Since the close and latch (momentary) rating of a breaker is the maximum fundamental frequency rms fault current the breaker can withstand, it can also be considered a measure of the forces which may be safely imposed on the various physical members of the breaker during a rated frequency (i.e., 60 Hz) fault condition.

To determine if the capacitor contributions could affect breaker or fuse interrupting capability, the I^2t energy in Joules was calculated for the capacitor and 60 Hz fault current and compared. The energy was calculated for each of the cases described above. The fault

current was based on calculations over one 60 Hz cycle, as were the capacitor currents (which also saw some increase from the steady-state currents).

Figure 7-6 shows the I^2t energy for the case with 30 m of cable and a 10 Mvar capacitor. The I^2t from the capacitor current is approximately 14 percent (36 kJoules of energy) of the first full cycle of energy discharge, and is no longer changing since the capacitor has discharged. At the time of contact interrupting for a 5 cycle (3 cycle parting time) breaker, the capacitor energy is less than 3 percent of the total fault value. The higher curve in Figure 7-6 represents I^2t and the lower curve represents the capacitor current.

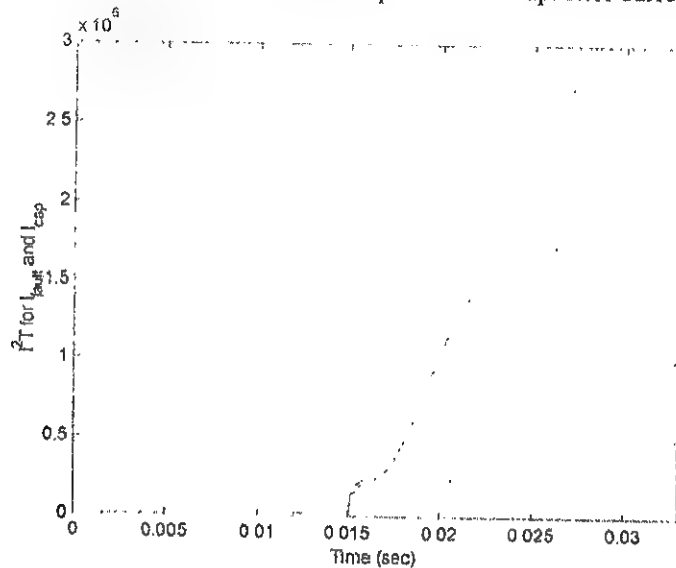


Figure 7-6— I^2t calculations for capacitor current and total fault current with 30 m of cable and 10 Mvar of capacitance

Figure 7-7 shows the I^2t for the fault current and the capacitor current for the case with 15 m of cable. The capacitor discharge current experiences little ringing with the short cable, so there is minimal contribution to the total I^2t . The higher curve in Figure 7-6 represents I^2t and the lower curve represents the capacitor current.

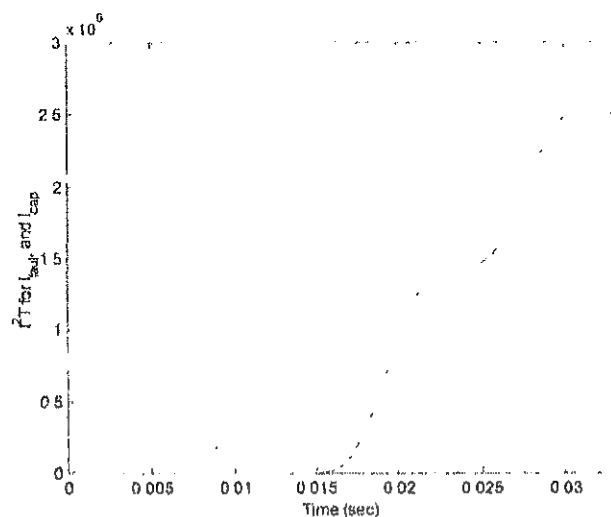


Figure 7-7— I^2t calculations for capacitor current and total fault current with 15 m of cable and 10 Mvar of capacitance (capacitor I^2t multiplied by 100 for plotting)

Figure 7-8 shows approximately the same I^2t ratio, as with 30 m of cable, indicating breaker interruption should not be affected. Note that in all three cases, the I^2t of the fault current is basically the same, and only the capacitor current changes. The higher curve in Figure 7-6 represents I^2t and the lower curve represents the capacitor current.

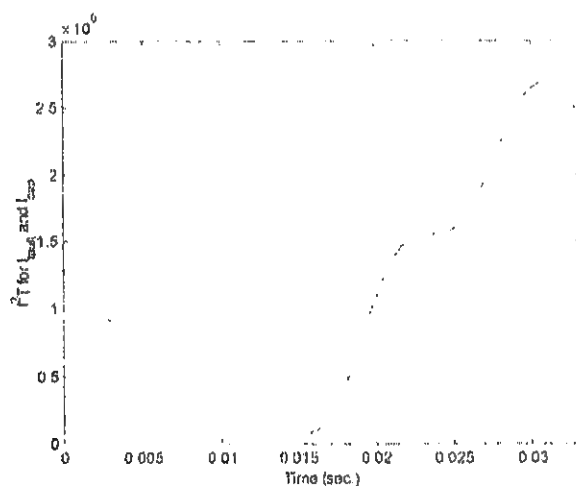


Figure 7-8— I^2t calculations for capacitor current and total fault current with 300 m of cable and 10 Mvar of capacitance

Another concern is closing the capacitor bank into a fault when there is trapped charge on the capacitor. The capacitor will usually be charged to either the positive or negative peak

line-to-neutral voltage, since the current zero will be 90° out of phase with the voltage. The resulting oscillations will be similar to what we see in the simulations below. Figure 7-9 shows the results of such a situation. Note the initial fault current and then the addition of the capacitor current. The response of the capacitor current is similar to that of Figure 7-3 (with the distributed parameter cable model). The timing of the closing of the breakers as well as the model detail will also impact the results.

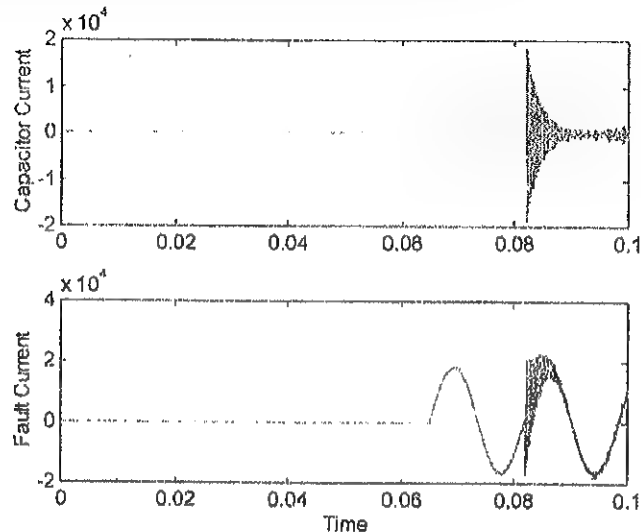


Figure 7-9—Closing capacitor into a fault with the capacitor current in the top plot and the fault current in the lower plot

7.3.2 Harmonic filter bank

Harmonic filter banks are found increasingly in industrial facilities in response to the increased use of adjustable frequency drive systems (AFDs) and non-linear heating systems (arc-furnaces). Filters may be found on both low- and high-voltage systems, although larger capacitor banks are generally associated with higher voltages.

Capacitors used in filter application are also cable connected, but include a reactor with a high X/R ratio. The overall X/R ratio is in the range of 10 to 50, which may significantly decrease the circuit damping. Figure 7-10 shows the system used to model a fifth harmonic filter bank.

Figure 7-11, Figure 7-12, Figure 7-13, and Figure 7-14 show the effect of the fifth harmonic filter on the fault current with increasing capacitor bank sizes. Fifteen meters of 3-1/C-500 kcmil copper conductor connects the filter to the bus. Notice the 2 Mvar filter is a near sine wave discharge with a peak fault current of 31 443 amperes and the 5 Mvar filter starts to show additional distortion. Note the filter current shows little damping in either case, so the resonant current excited by the fault will take a considerable time to damp out. As the filter size increases to 10 and 20 Mvar the discharge oscillates with an exchange of energy between the capacitor and reactor at the characteristic frequency of the filter (fifth harmonic). The short-circuit current has increased slightly to 33 234 and

33 285 amperes respectively. This is due to the increase in pre-fault voltage from the capacitors, not to the capacitor discharge current.

The simulation time was extended to 3 cycles to better determine the length of the discharge in the 10 Mvar and 20 Mvar cases. As can be seen, the oscillations last approximately one cycle; however, the peak asymmetrical current is only 33 009 amperes, and now appears on different phases than was the case with the capacitors instead of filters, even if the filter current is smaller on that phase. This change results from the filter inductance slowing down the ringing of the capacitor current, and limiting the peak contribution from the capacitor. The 5% increase in peak asymmetrical current is due to the increase in pre-fault voltage.

Harmonic filter connections show a decrease in transient discharge currents as compared to a non-filtered bank. The energy exchange between the capacitor reactor combination oscillates at the characteristic filter frequency, and the decay rate is damped as the RLC time constant increases.

The high X/R ratio of the reactors increased the time constant significantly, however, the added reactor impedance limited the expected high-frequency discharge to normal system fault levels. Breaker, fuse, or switch operation should not generally be affected with this combination. Figure 7-15 shows the I^2t curves for the fault current and the filter current for the case with a 15 meter cable and a 10 Mvar capacitor. Notice that at 33 milliseconds, the I^2t for the fault current is basically the same as it was with just a 10 Mvar capacitor in Figure 7-7. The filter contribution continues to increase, since the filter current rings down slowly.

In Figure 7-15, the higher curve represents the I^2t of the total current while the lower curve represents the I^2t of the filter current.

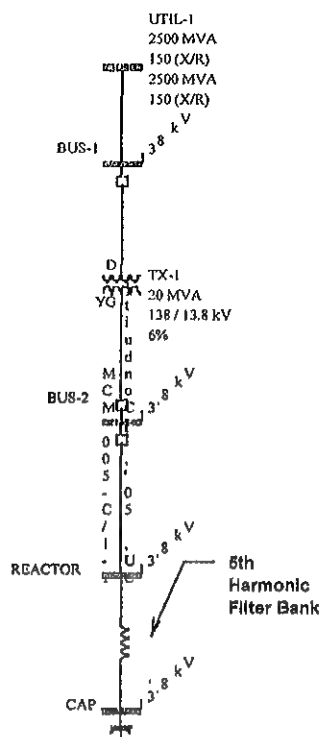


Figure 7-10—One-line diagram for example case with harmonic filter bank

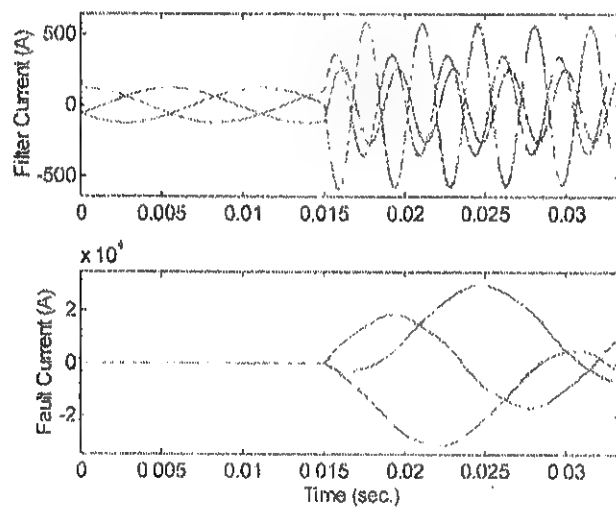


Figure 7-11—Simulation results with 2 Mvar filter and 15 m of cable

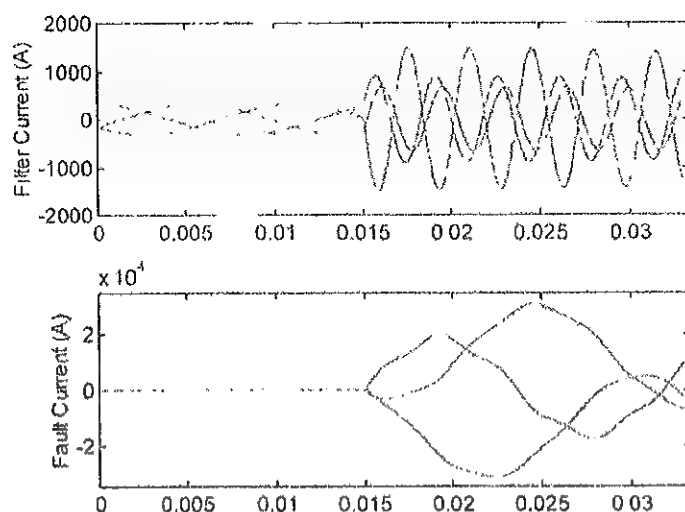


Figure 7-12—Simulation results with 5 Mvar filter and 15 m of cable

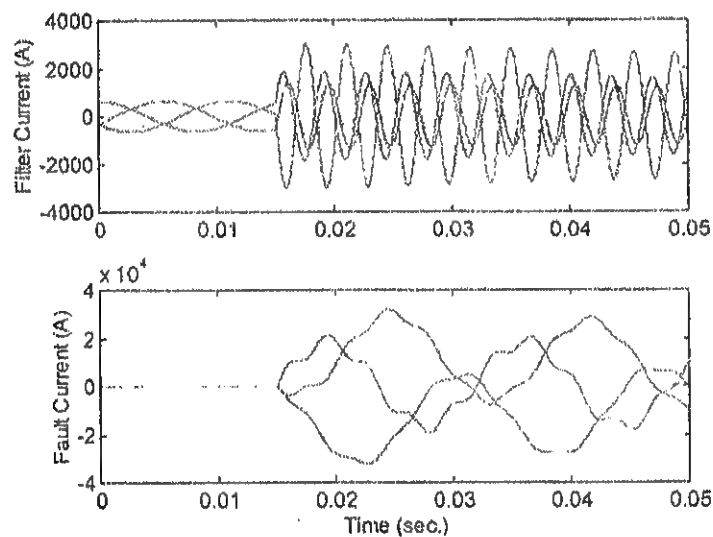


Figure 7-13—Simulation results with 10 Mvar filter and 15 m of cable

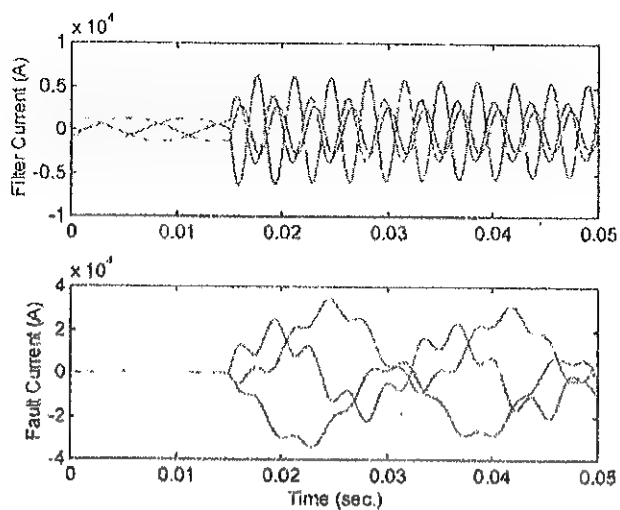


Figure 7-14—Simulation results with 20 Mvar filter and 15 m of cable

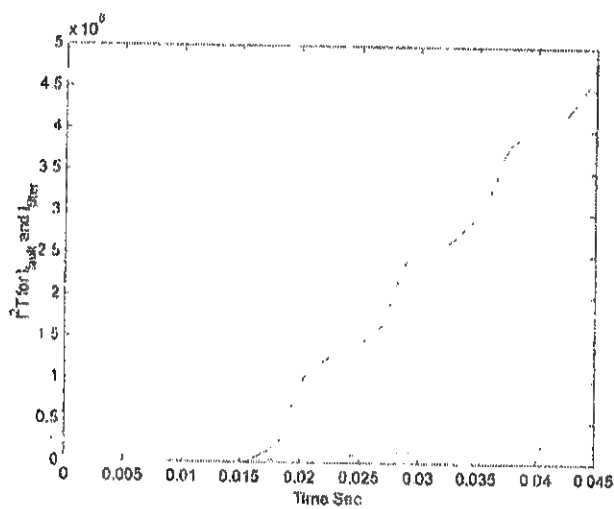


Figure 7-15— I^2t calculations for capacitor current and total fault current with 1000 foot of cable and a fifth harmonic filter with 10 Mvar of capacitance

7.3.3 Medium-voltage motor capacitors

The impact of medium-voltage motor capacitors was also modeled to determine the effect of capacitor discharge along with that of the motor during a fault. Figure 7-16 shows the system used to model the medium-voltage motor capacitor combination.

A three-phase bolted fault was placed on the 13.8 kV bus at a steady-state time of 36 ms. The faults were initiated at voltage peak in order to maximize the current offset. The initial fault current without capacitors was calculated as 33 852 amperes as shown in Figure 7-17. The figure shows the fault current contribution from the source, from the motor, and the total fault current on the same set of axes.

Figure 7-18 shows the results of a 1 Mvar capacitor in parallel with the 4-pole induction motor. The first plot shows the capacitor current and the second shows the total fault current. The motor and source currents are essentially unchanged, and are not shown. Notice that the amplitude of the capacitor current is very small relative to the total fault current.

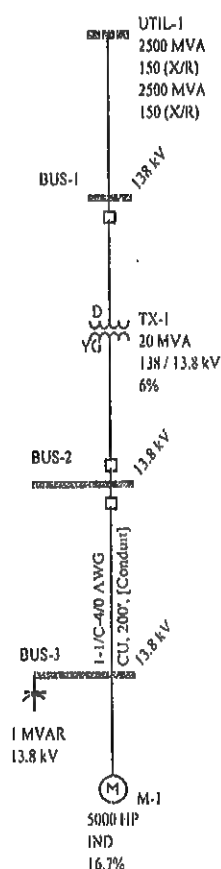


Figure 7-16—One line diagram of example system with motor and motor capacitor

As can be seen, there is some initial discharge below 2 ms, which is characteristic of the standard capacitor bank results. The interaction and energy exchange with the parallel motor capacitor combination may actually damp the discharge somewhat. Maximum fault current was increased slightly to 33 963 amperes with capacitor addition due to the increase in pre-fault voltage. Similar results are seen for different sized capacitor banks.

Medium-voltage motor capacitors are small enough that they show no significant increase to the normal system fault levels.

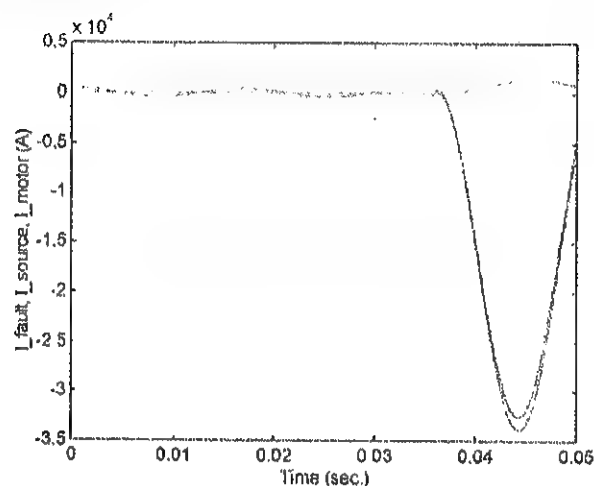


Figure 7-17—Simulation results with capacitors disconnected (fault current, source current and motor current)

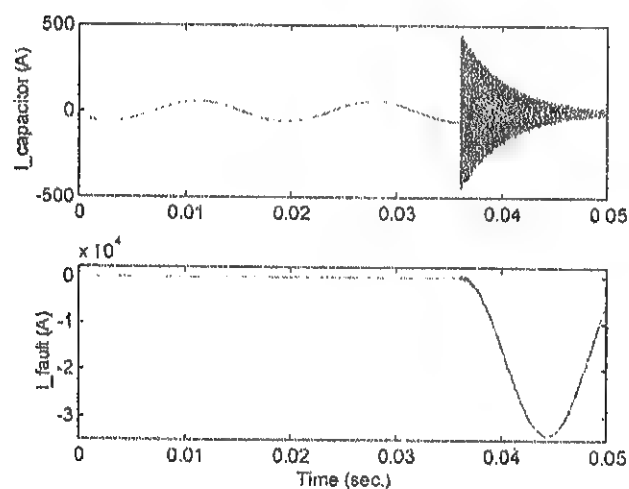


Figure 7-18—Simulation results with capacitors connected to the system (The capacitor current is shown in top plot and the fault current in the lower plot.)

7.3.4 Low-voltage motor capacitors

Low-voltage motor capacitors were modeled to determine the effect of capacitor discharge with the motor during a fault. Figure 7-19 shows the system used to model the low-voltage motor capacitor combination.

A three-phase bolted fault was placed on the 480-volt bus at a steady-state time of 36 ms. The faults were initiated at voltage peak in order to maximize the current offset. The initial fault current without capacitors was calculated as 33 193 amperes as shown in Figure 7-20. The figure shows the current contribution from the source, the motor current, and the total fault current. Figure 7-21 shows the results of a 200 kVAR capacitor added to the switchgear bus. The first plot shows the capacitor current and the second plot shows the total fault current. Again, the source and motor contributions are largely unchanged.

As can be seen, there is no visible discharge below. Maximum fault current was increased slightly to 33 378 amperes with capacitor addition limited currents due to the increase in pre-fault voltage. Low-voltage motor capacitors are small enough that they show no significant increase to the normal system fault levels.

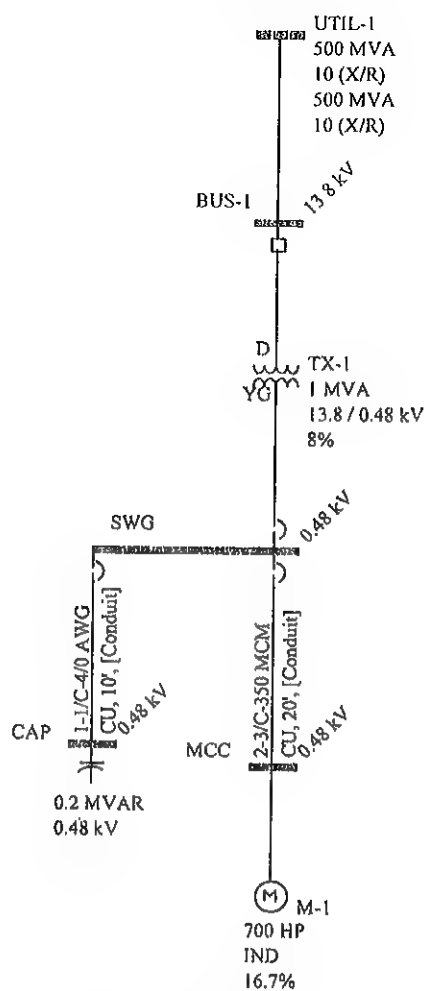


Figure 7-19—One line diagram of example system with low-voltage motor capacitors

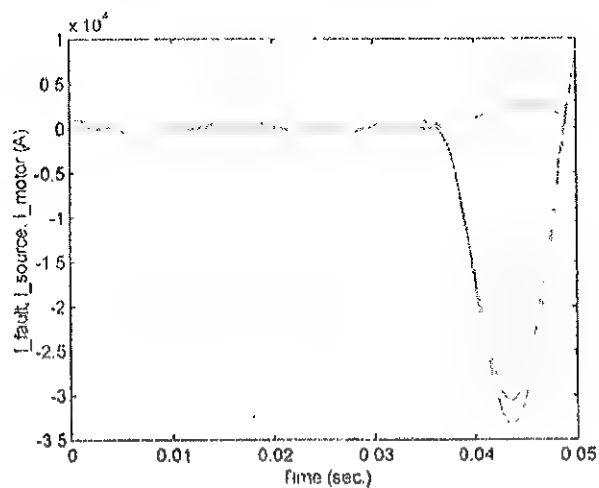


Figure 7-20—Simulation results with capacitors disconnected (fault current, source current and motor current)

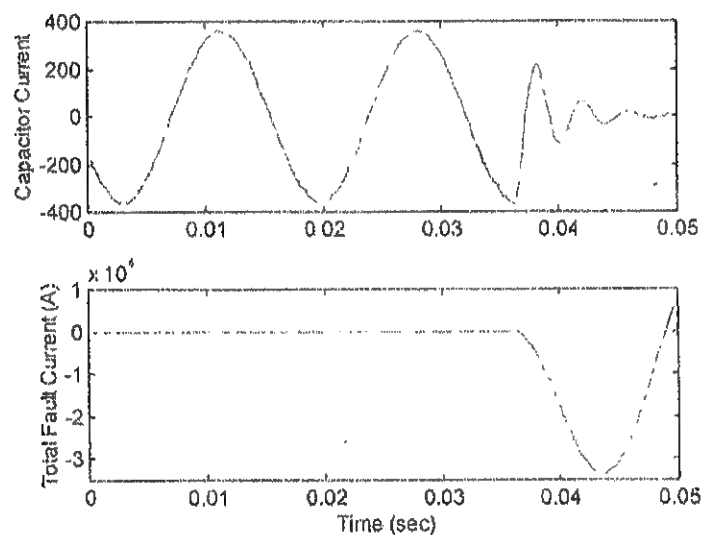


Figure 7-21—Simulation results with capacitors connected to the system (The capacitor current is shown in top plot and the fault current in the lower plot.)

7.4 Summary

During fault conditions, the capacitor discharge takes place in the initial 1/30–1/8 cycles, depending on the time constant of the system. Since the breaker protective device and contacts cannot operate in this time frame, the discharge takes place into closed contacts. The electro-magnetically induced forces of the discharge current are instantaneously proportional to the current squared. Since the close and latch (momentary) rating of a breaker is the maximum fundamental frequency rms fault current the breaker can withstand, it can also be considered a measure of the forces which may be safely imposed on the various physical members of the breaker during a rated frequency (i.e., 60 Hz) fault condition.

Based on the simulations shown in this chapter, capacitor discharge currents will have no effect on breaker parting or clearing operations. Some small additional stresses may be imposed for the closing and latching duty for very large capacitor banks. However, it should be noted that the models developed in this chapter were sized larger than standard design practices in order to determine any potential problems.

At this point, the standard cannot recommend that capacitors be added to system simulations for breaker duty calculations. The existing ANSI C37 series fault calculation methodologies remain adequate for the determination of breaker, fuse, and switch duties.

7.5 Bibliography

[B1] Greenwood, A., *Electrical Transients in Power Systems*, Second Edition. Wiley-Interscience, 1991.

Chapter 8

Static converter contributions to short-circuit currents

8.1 Introduction

This chapter examines how static power converters influence ac short-circuit currents. The purpose of this chapter is to define when and how much a converter increases the calculated short-circuit current for a fault nearby on the ac supply system. The chapter also analyzes currents to dc short circuits in the converter equipment, pointing out that, under certain circumstances, these fault currents may be larger than the normally calculated maximum three-phase short-circuit currents. Before any equations or calculations are presented, some definitions of converter types and their possible fault conditions are given.

8.2 Definitions of converter types

A power converter links two systems with different frequencies or to a dc voltage.

A static power converter is a converter that employs static switching devices such as diodes, SCRs, metallic controlled rectifiers, transistors, electron tubes, or magnetic amplifiers. All these types of switching devices will be called valves in this chapter. All valves may be considered in two groups: without or with a grid control system; the corresponding converters are referred to as non-controlled or controlled. The difference between the two is that non-controlled converter's valves conduct at moments when the valve voltage becomes positive and controlled converter's valves conduct at moments when the valve voltage is positive and a grid-control pulse is supplied. The angle between the moment when the valve voltage becomes positive and the moment the grid-control pulse is supplied is called the firing angle ($0 \leq \alpha \leq 180^\circ$).

The damage of a short circuit in a controlled converter system can be significantly limited by the grid-control protection system. A grid-control protection system enables the grid firing circuit to detect abnormal conditions and stop sending grid pulses. The current flow to a converter short circuit is limited to one cycle by the normal action of the grid protection system.

There are four main types of converters:

- 1) *Rectifier*—A converter that converts alternating current/voltage to direct current/voltage (ac to dc).
- 2) *Inverter*—A converter that converts direct current/voltage to alternating current/voltage (dc to ac).
- 3) *Cycloconverter*—A converter that converts alternating current of one frequency to alternating current of another frequency (ac to ac).
- 4) *Chopper*—A converter that converts dc to dc of another voltage.

In this chapter, in addition to dc contributions through inverting converters to ac short circuits, dc short circuits in rectifiers and inverters and their current from the ac system are analyzed and calculated.

8.3 Converter circuits and their equivalent parameters

There are many types of converter circuits; however, two are the most common and they are analyzed in this chapter. These two circuits are the three-phase half-wave circuit (Figure 8-1a) and the three-phase full-wave circuit also known as the three-phase bridge (Figure 8-1b). These circuits are used in all types of converters such as rectifiers, inverters, and cycloconverters.

The ac equivalent circuits of the converters are shown in Figure 8-2a and Figure 8-2b where the ac system and transformer are changed to the symmetrical three-phase voltages labeled e_1 , e_2 , and e_3 , and the current in each phase is limited by system and transformer inductive reactance X_γ and resistance R_γ . The formulae for the X_γ calculations are as follows:

$$X_\gamma = X_t + (V_2/V_1)^2 \times X_s \quad (8.1)$$

$$X_s = V_1^2/S_{sc} \quad (8.2)$$

$$X_t = (X_t\%/100) \times V_2^2/S \quad (8.3)$$

$$V_2 = \frac{\sqrt{3}}{\sqrt{2}} E_m \quad (8.4)$$

where

X_s	is the equivalent inductive system reactance
V_1	is the effective value of the system line-to-line voltage
S_{sc}	is the three-phase short-circuit power (available short-circuit MVA) of the ac system at the transformer primary terminals
X_t and $X_t\%$	is the inductive reactance of the transformer in ohms and in percentage
V_2	is the effective value of the line-to-line voltage of the transformer secondary winding under no load conditions
S	is the rated MVA power of the transformer
E_m	is the peak amplitude of the transformer secondary winding phase voltage.

(See Figure 8-1a and Figure 8-1b.)

The equation for the R_γ calculation is similar to Equation (8.1), Equation (8.2), and Equation (8.3) with each X value changed to the corresponding R value.

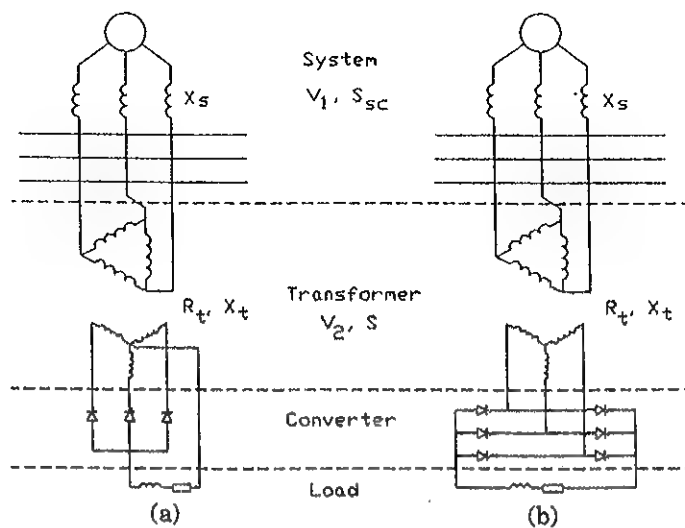


Figure 8-1—Converter circuits and their connections
(a) Half-wave converter
(b) Full-wave converter

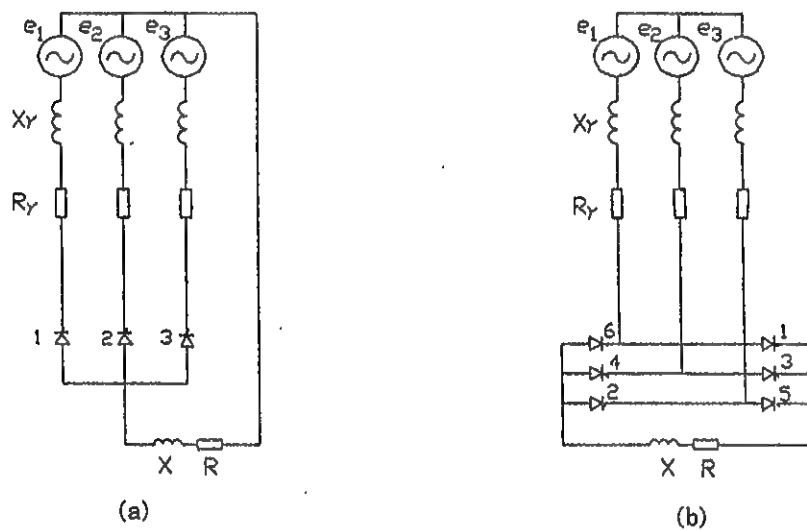


Figure 8-2—AC equivalent circuit of converters
(a) Half-wave converter
(b) Full-wave converter

8.4 Short-circuit current contribution from the dc system to an ac short circuit

This analysis considers an ac short circuit with a dc current contribution from a dc machine that is SCR-fed from the ac system.

The dc system contributes current to an ac short circuit only when the converter operates as an inverter. Only then can the dc system feed energy to the ac system. Because non-regenerative motor drives cannot operate in inverter mode (as viewed by the ac system), they are not considered for short-circuit calculations. The circuit for analysis is developed from Figure 8-1 by changing load resistance R to a dc source E_d with internal resistance R_d , as shown in Figure 8-3. The inverter circuit operates with SCRs; only SCR converters are analyzed here.

The dc sources of voltage E_d that are of principal interest in this text are dc machines, normally motors but operating transiently as generators while their converters are inverting. Other possible sources, some having different characteristics for E_d , include batteries (perhaps in Uninterruptible Power Supplies), photo-voltaic arrays, and inverters (perhaps of dc transmission lines); these are only of passing interest in industrial or commercial building power systems.

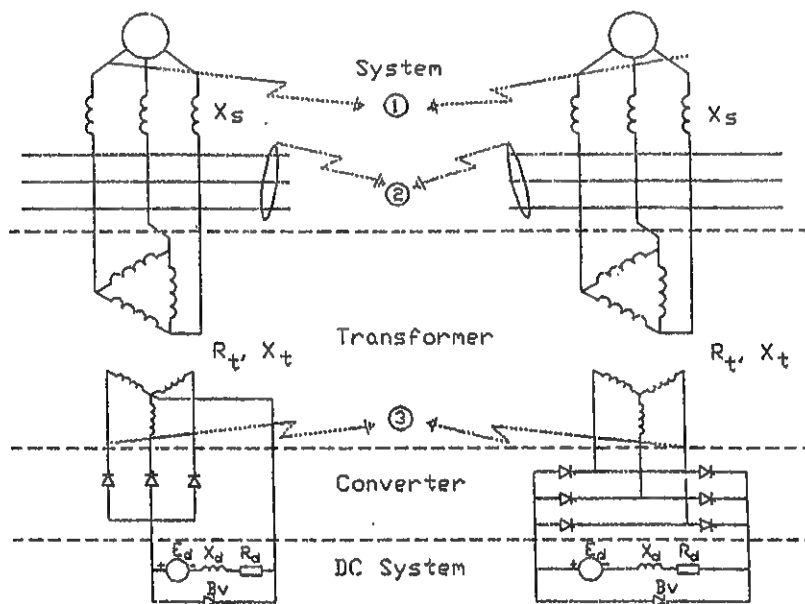


Figure 8-3—Equivalent diagram with inverter source and possible points of short circuits on ac side

1. High-voltage primary of supply transformer
2. High-voltage primary of converter transformer
3. Low-voltage secondary of converter transformer

Only dc machine sources are analyzed in this chapter. Under normal operating conditions, the voltage E_d and the voltage u_d on the converter terminals, produced by the ac voltage E_{\sim} , are practically equal, and rated currents I_{\sim} and I_d flow in the ac and dc systems, as in Figure 8-4. When the ac short circuit occurs, short-circuit currents flow to it from the ac system and may flow also from the dc system if the converter is inverting. The largest short-circuit currents flow when the voltage E_{\sim} falls to zero. This occurs with a three-phase symmetrical ac short circuit at any one of the points 1, 2, or 3 in Figure 8-3 between the ac system and the converter. In this case, the ac and dc fault currents are independent of each other, can be determined separately, and add together only at the fault point.

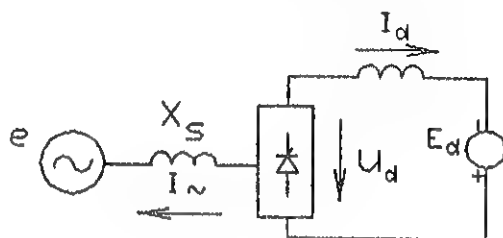


Figure 8-4—Simplest equivalent diagram of ac and dc systems

The equivalent diagrams for the half wave and full wave converters with an ac short circuit are shown in Figure 8-5, where the symbols are as follows:

- R_1, X_1 = total resistance and reactance between the converter and the point of ac short circuit
- BV = the bypass valve
- R_d, X_d = the total resistance and reactance of the dc elements

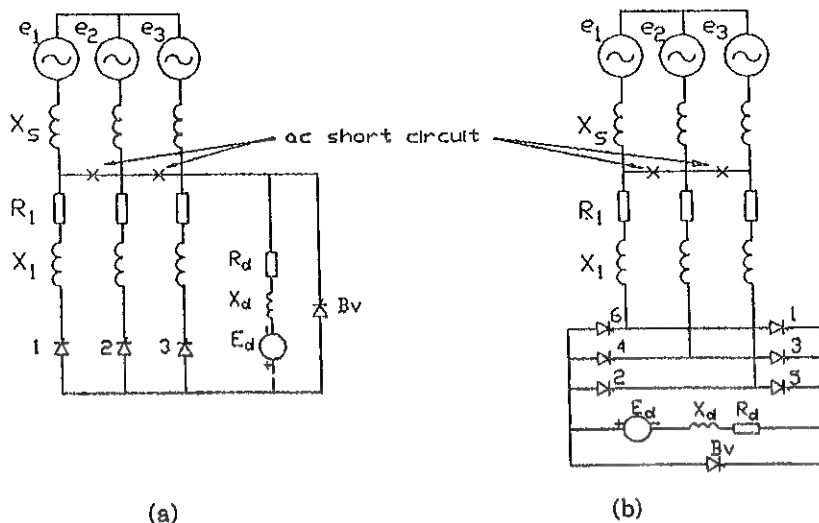


Figure 8-5—Equivalent diagram of half-wave (a) and full-wave (b) converters with the short-circuit on the ac side

If the grid-control protection system operates, the BV is fired immediately after the ac short circuit occurs. This diverts the dc contribution to the ac short circuit (the dc system current flows through the BV) and the dc system contributes to the short-circuit current only for the short time (less than one cycle) before the BV fires.

If the grid-control protection system does not operate, the grid pulses are not supplied to the valve grids and the valves that are conducting when the ac short circuit occurs continue to conduct current from the dc motor acting as a source to the ac short circuit. For conservatism, the initial analysis assumes the dc machine has electrical armature transients that are faster than mechanical (slowdown) and electrical field transients, permitting the assumption that back emf E_d is essentially constant. For this assumption, the equivalent diagrams for the fault of the half-wave and full-wave converters during non-commutating and commutating intervals are shown in Figure 8-6 and Figure 8-7. The resultant circuits are linear RL circuits with source E_d . The standard equation for such circuits is shown in Equation (8.5).

$$i = I_{\Sigma} \times (1 - e^{-t/\tau}) + i(0) \times e^{-t/\tau_{dc}} \quad (8.5)$$

The maximum value of current, at $t = \infty$, is equal to:

$$I_{\Sigma} = E_d / r_{\Sigma} \quad (8.6)$$

where

E_d is a constant

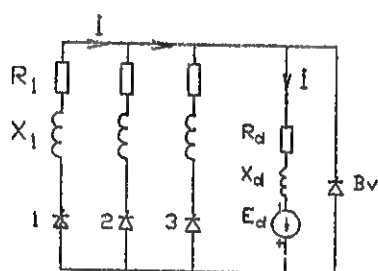
$\tau_{dc} = R_{\Sigma} / L_{\Sigma}$ is the time constant in seconds of the dc short-circuit current

R_{Σ} and L_{Σ} are the total resistance and inductance of the dc circuit to the ac short-circuit point
 $i(0)$ is the initial dc circuit current

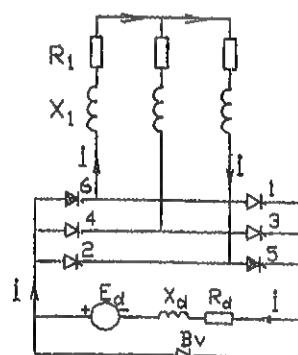
The magnitudes of R_{Σ} for different converters and short-circuit current paths are shown in Table 8-1, refer to Figure 8-6 and Figure 8-7. Values of L_{Σ} are obtained from Table 8-1 by changing each resistance R to the corresponding value of inductance L . If X is known instead of L , divide it by $2\pi f$.

Table 8-1—Magnitudes of R_{Σ}

Current paths	Half wave	Full wave
One (non-commutating interval)	$R_1 + R_d$	$2 \times R_1 + R_d$
Two (commutating interval)	$(R_1/2) + R_d$	$(3 \times R_1/2) + R_d$



(a)



(b)

Figure 8-6—Equivalent diagram of half-wave (a) and full-wave (b) converters for the dc contribution to an ac short-circuit during a non-commutation interval

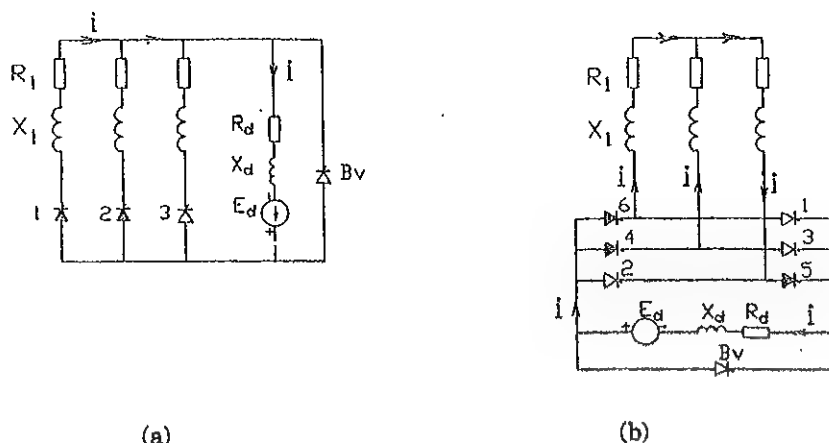


Figure 8-7—Equivalent diagram of half-wave (a) and full-wave (b) converters for the dc contribution to an ac short-circuit during a commutation interval

For dc machines with comparably fast mechanical and electrical transients, the dc source may be represented as a capacitor with an initial voltage E_d . The equivalent circuit is an RLC circuit, Figure 8-8(a). The equivalent capacitance C represents the dc machine slowdown including the influences of inertia, mechanical load and friction on speed decay and of field current decay on voltage. The current of the equivalent circuit is a damped sinusoid, Figure 8-8(b), with a highest first peak and initial rate of rise both lower than for the RL circuit. A more complete analysis covering this is not included here because it is conservative to analyze all cases using the RL circuit.

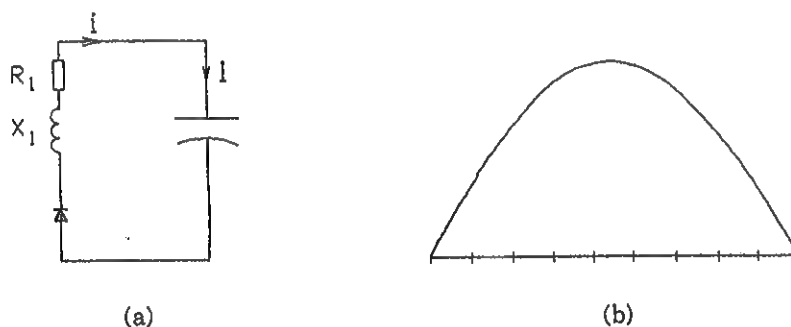


Figure 8-8—Equivalent diagram of oscillatory circuit (a) and short-circuit current (b)

The following summarizes the preceding analysis of the contributions of dc machines to ac short-circuit currents:

- a) If the grid-control protection system operates to fire a bypass valve, the dc system contributes to the short-circuit current only for the short time (less than one cycle) before the BV fires.
- b) If the grid-control protection system does not operate, the contribution of dc short-circuit current depends on the character of the source. $I_{\Sigma} = E_d/R_{\Sigma}$ final maximum dc current applies for a dc machine with electrical armature transients faster than mechanical and dc field transients so that the voltage source E_d is constant and the equivalent circuit is an RL circuit.

Note that the dc short-circuit current contributed in the real system will be smaller than calculated here not only due to dc machine slowdown but also due to the damping of dc currents in the converter transformers. Other effects of high magnitude dc currents that are difficult to evaluate quantitatively also tend to limit the magnitude or duration of the dc contribution. These include tripping of dc circuit breakers, blowing of SCR valve fuses, and possibly dc machine commutator flashovers. Since the current flow to a converter short circuit is limited to one cycle by the normal action of the grid protection system, it is necessary to calculate only the dc current contribution that adds to the ac first cycle peak and rms short-circuit current. The dc short-circuit current contribution may also have a strong influence on the after-fault system recovery, because it tends to saturate the converter transformer core. When the short circuit is cleared and the ac primary bus is reenergized, there may be a very large inrush of current to the transformer.

The highest peak current of the ac system short circuit, I_{acpeak} , before it is increased by the dc current contribution through the inverting converter from the dc machine, occurs during the first cycle of the most offset phase current. It was noted in Chapter 2 that peak ac depends on the symmetrical component of the ac current, $I_{sym, peak}$, and the fault point X/R ratio to be approximately:

$$I_{ac, peak} = I_{sym, peak} [1 + e^{-2\pi\tau(X/R)}] \quad (8.7)$$

where $\tau = 0.49 - 0.1e^{-(X/R)/3}$

The most offset ac system current reaches this highest peak in less than one half cycle (at system frequency) after the short circuit occurs. To use a conservative simplification, the transiently increasing dc current fault contribution, i_c , that is added to the first cycle peak ac current, is calculated at the half cycle time (0.00833 seconds at 60 Hz or 0.01 seconds at 50 Hz).

The magnitude of the dc current fault contribution i_c at a time equal to one-half cycle at system frequency is shown in Equation (8.8) [from Equation (8.5)]:

$$i_c = I_d - (I_d - i(0))e^{-\pi(X_{\Sigma}/R_{\Sigma})} \quad (8.8)$$

To summarize, the dc contribution of a controlled or non-controlled inverting converter to an ac system short-circuit current is estimated by adding i_c at one-half cycle based on system frequency to the highest first cycle ac peak current.

The “source plus impedance” circuit component that represents the dc machine contributing through an inverting converter in the equivalent circuit for an ac short-circuit calculation, as recommended by IEC 60909-0:2001 [B7]¹, is the same as that of an induction motor. This circuit component has an impedance corresponding to an “equivalent locked rotor current” of 3.0 per-unit, ($X'' = 33\%$) based on the ac three-phase apparent power input of the converter transformer (or of the converter if there is no transformer) at rated dc machine load and an equivalent X/R ratio of 10. The Grotstollen investigation [B3] is essentially in agreement with this equivalent representation.

8.5 Analysis of converter dc faults

There are two types of converter short circuits that cause the flow of large currents in ac supply systems: one is a short circuit between the dc terminals of a converter and the other is a short circuit of one of the converter valves also called an “arc-back.”

The short circuit effects can be very severe if the grid-control protection system does not operate and grid pulses continue to be supplied under fault conditions. The most severe faults occur in diode converters where there is no grid-control protection system.

The short circuits analyzed in this chapter are as follows:

- 1) A short-circuit between the dc terminals of a converter with a grid-control protection system.
- 2) A short-circuit between the dc terminals of a converter without a grid-control protection system.
- 3) An arc-back with a grid-control protection system.
- 4) An arc-back without a grid-control protection system.

Short circuits are analyzed in the above sequence for the half- and full-wave converters, shown in Figure 8-1 and Figure 8-2. All calculations are carried out for the no-load initial condition when the fault current is maximum.

The full analysis of a converter dc short circuit (not within the scope of this text) includes the definition and solution of sets of linear differential equations and/or difference ts for the various types of short-circuit currents. The fault currents depend on the resistance and reactance of the ac system and the moment when the short circuit occurs.

To simplify the analysis, the following assumptions are made:

- a) The short-circuit current path for each case is as shown on the figures illustrating the circuit diagram for the case.
- b) The short-circuit currents are calculated neglecting circuit resistance. These currents can be modified to account for the damping due to resistance by Equation (8.7) using $X\gamma/R\gamma$.
- c) The term $I_m = E_m/X\gamma$ is used in all equations.

¹The numbers in brackets correspond to those of the bibliography in 8.10.

The parameters E_m , X_γ , and R_γ are defined in 8.3. I_m is the peak of the symmetrical phase current to a three-phase ac short circuit at the ac input terminals of the converter.

A dc short circuit inside or at the dc output terminals of a converter may have currents similar magnitude to those of a three-phase ac short circuit at the ac input terminals, but the peak short-circuit currents can be larger than the $2I_m$ calculated for the ac short circuit.

8.6 Short circuit between the converter dc terminals

The first fault considered is a short circuit between the dc terminals of the half-wave converter shown in Figure 8-9. This short circuits every ac phase. If the grid-control protection system operates, the fault current flows only in the one phase whose voltage is the most positive at the moment when the fault occurs. The other two phases have no fault currents because the grid-control protection system feeds no grid pulses, as in line (2), Figure 8-10. The equivalent three-phase voltages of line (1) of Figure 8-10 are shown in Equation (8.9):

$$e_1 = E_m \times \sin(\theta + 30^\circ) \quad e_2 = E_m \times \sin(\theta - 90^\circ) \quad e_3 = E_m \times \sin(\theta + 150^\circ) \quad (8.9)$$

where E_m is the maximum amplitude of the phase voltage.

The short-circuit current has a maximum peak when the fault occurs at $\theta = \alpha$ firing angle, and the grid impulse is supplied to phase 1, see location (2), Figure 8-10. The equation for the current from the ac system to the dc short circuit is shown in Equation (8.10):

$$i_{sc} = I_m (\cos(\alpha + 30^\circ) - \cos(\alpha + \theta + 30^\circ)) \quad (8.10)$$

where $i_{sc} = 0$ at $\theta = \alpha$, locations (3) and (4), Figure 8-10, and $I_m = E_m/X_\gamma$ is the peak of the symmetrical ac current to a three-phase bolted short circuit at the converter input terminals.

The non-damped peak of the ac current to the dc short circuit is shown in Equation (8.11):

$$i_{psc} = I_m (1 + \cos(\alpha + 30^\circ)) \quad (8.11)$$

The actual peak magnitude of the decaying ac current to the dc short circuit accounting for resistive damping, R_γ , is obtained using the dependent multiplying factor, $MF_{default}$, derived from Equation (8-7). I_m replaces $I_{sym, peak}$ or $\sqrt{2}I_{sym}$ and $MF_{default} = (\text{first cycle asymmetrical current})/(\text{peak of ac symmetrical current})$.

$$MF_{default} = I_m [1 + e^{-2\pi\tau(X_\gamma/R_\gamma)}] \quad (8.12)$$

where $\tau = 0.49 - 0.1e^{-2\pi\tau(X_\gamma/R_\gamma)/3}$

If the grid-control protection system does not operate, the analysis is similar to the above except the short circuit currents flow in all three ac phases and repeat every cycle as shown in Figure 8-11.

In the case of the diode converter there is no grid-protection system. The diodes begin to conduct when their anode voltages become positive. The equation for the current from the ac system to the dc short circuit is shown in Equation (8.13):

$$i_{sc} = I_m(1 - \cos \theta) \quad (8.13)$$

and its non-damped peak value is shown in Equation (8.14):

$$I_{psc} = 2I_m \quad (8.14)$$

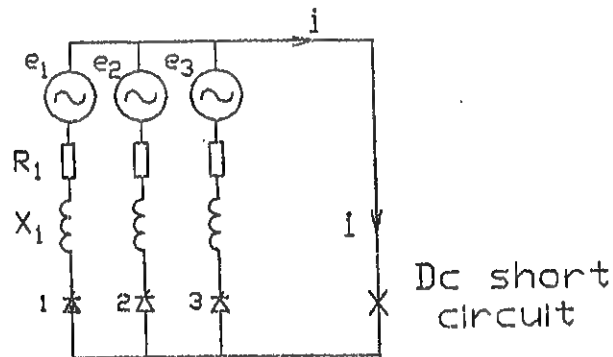
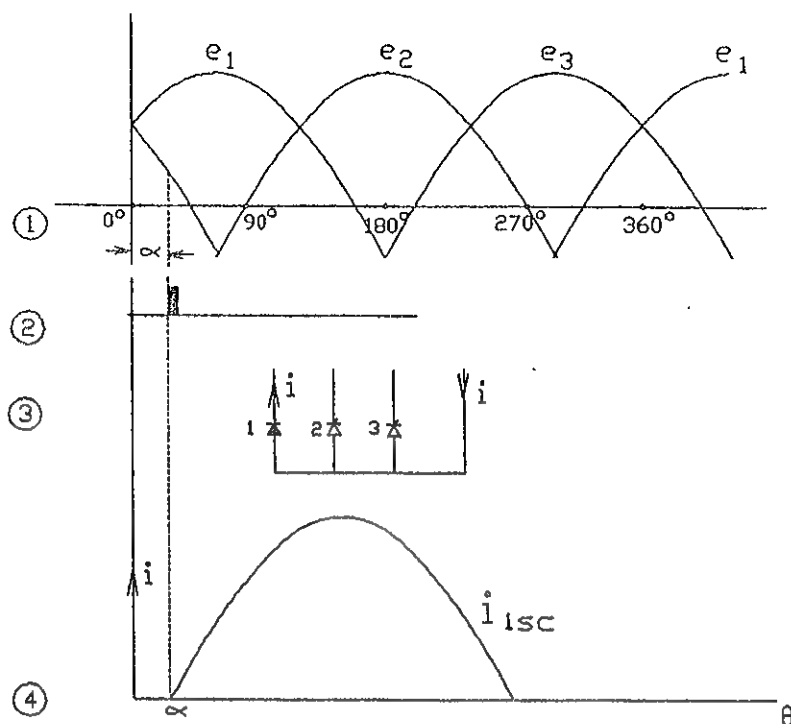


Figure 8-9—DC short-circuit between half-wave converter terminals



**Figure 8-10—DC terminal short-circuit in a half-wave SCR converter
(grid protection system operates)**

1. Three-phase voltage system
2. Grid impulse
3. Fault loop
4. Fault current in phase 1 only

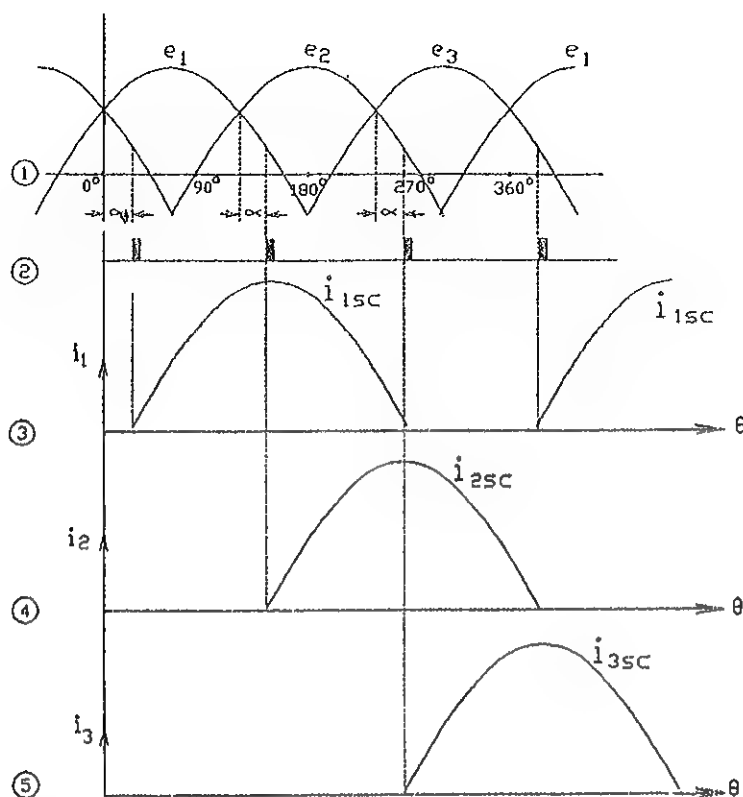


Figure 8-11—DC terminal short-circuit in a half-wave SCR converter (grid protection system does not operate)

1. Three-phase voltage system

2. Grid impulse

3,4,5. Fault current in phase 1, 2, and 3.

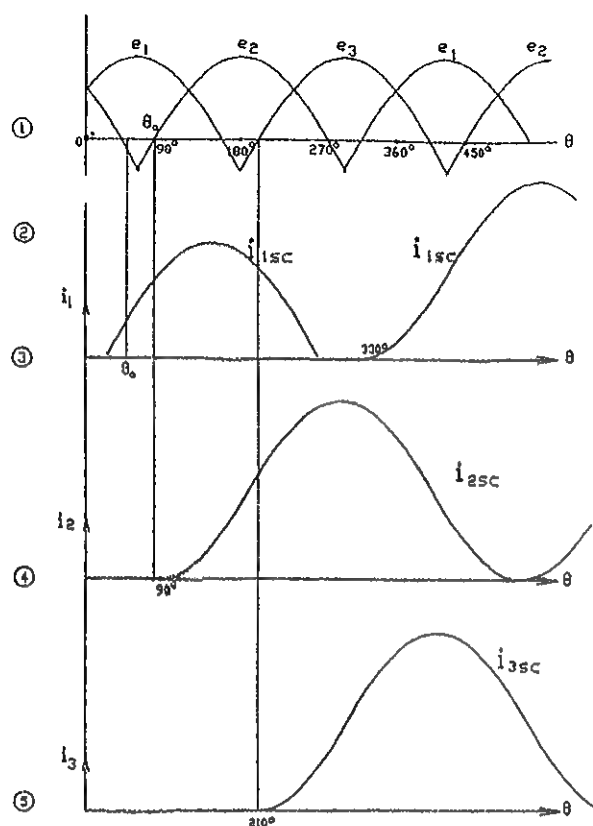


Figure 8-12—DC terminal short-circuit in the diode half-wave converter

1. Three-phase voltage system
- 2,3,4. Fault current in phase 1, 2, and 3

The short-circuit currents flow in all three phases and repeat every cycle, as shown in Figure 8-12.

The actual peak magnitude of the decaying ac current to the dc short circuit accounting for resistive damping is obtained using Equation (8.12).

Consider next a short circuit between the dc terminals of the full-wave converter shown in Figure 8-13. The numbers of the valves in Figure 8-13 correspond to the valve firing sequence. If the grid-control protection system operates, there are two possible short-circuit current paths: one is with two valves conducting and the other is with three valves conducting at the moment of short circuit initiation. Both have the same maximum value

of current and therefore only the circuit with two firing valves will be analyzed, see Figure 8-14.

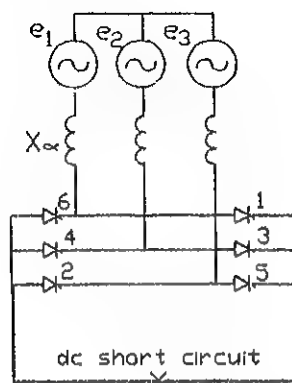
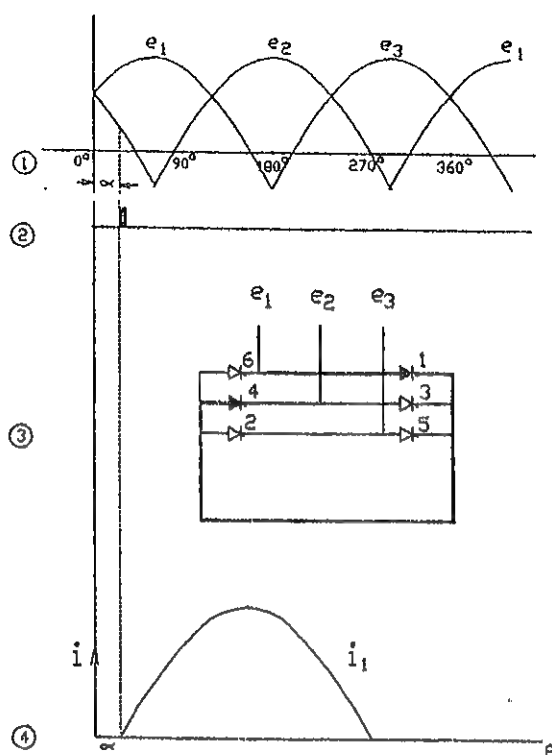


Figure 8-13—DC terminal short-circuit in a full-wave converter terminals



**Figure 8-14—DC terminal short-circuit in a full-wave SCR converter
(grid protection system operates)**

1. Three-phase voltage system
2. Grid impulse
3. Fault loop
4. Fault current

Assume the fault is initiated at the moment $\theta = \alpha$ and two valves 1 and 4 begin to conduct. The corresponding current from the ac system to this two-phase dc short circuit is shown in Equation (8.15):

$$i_{sc} = i_{1sc} = i_{4sc} = \left(\frac{\sqrt{3}}{\sqrt{2}} \right) \times I_m \times (\sin(\theta - 30^\circ) - \sin(\alpha - 30^\circ)) \quad (8.15)$$

and its non-damped peak value at $\alpha = 0$ is shown in Equation (8.16):

$$I_{psc} = \frac{3 \times \sqrt{3}}{4} I_m \quad (8.16)$$

The actual peak magnitude of the decaying ac current to the dc short circuit accounting for resistive damping is obtained using Equation (8.7).

If the grid-control protection system does not operate, the short-circuit current during the first 60° is the same as when the grid-control protection system operates. At the moment $\theta = 60^\circ + \alpha$, lines (1) – (4), Figure 8.15; however, valve 2 begins to conduct.

With three valves (4, 1, and 2) conducting, there is a three-phase dc short circuit in the converter. Taking into account the initial conditions, the three currents from the ac system to the dc short circuit are shown in Equation (8.17), Equation (8.18), and Equation (8.19):

$$I_{1sc} = I_m \left(1 + \frac{\sqrt{3}}{2} \times \cos \alpha - \sin \alpha \right) \quad (8.17)$$

$$I_{2sc} = I_m (1 + \cos \alpha \times \cos(\alpha + 30^\circ)) \quad (8.18)$$

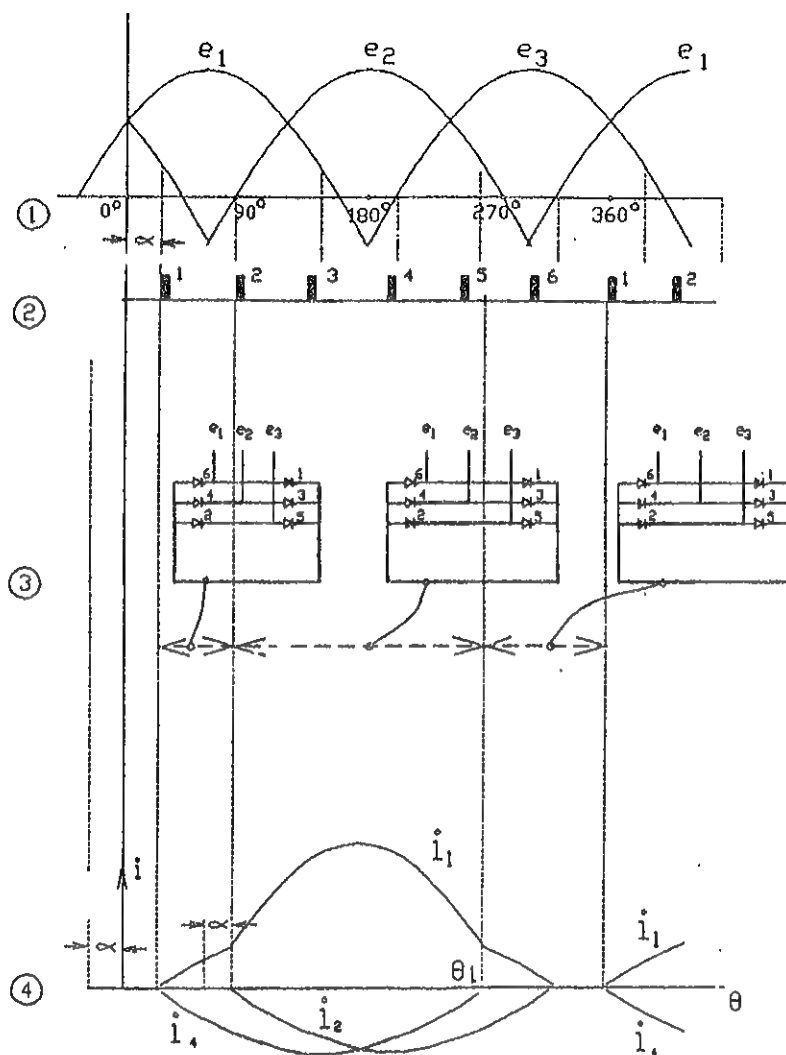
$$i_{3sc*} = I_m \left(1 + \frac{1}{2} \times \sin \alpha \right) \quad (8.19)$$

The non-damped peak values of the short circuit currents at $\alpha = 0$ are shown in Equation (8.20) and Equation (8.21):

$$I_{1psc} = I_{2psc} = \left(1 + \frac{\sqrt{3}}{2} \right) I_m \quad (8.20)$$

$$I_{3psc} = I_m \quad (8.21)$$

In this case, the fault current peaks are smaller than the maximum peak for a three-phase short circuit. This is similar to the short circuited half-wave controlled converter.



**Figure 8-15—DC terminal short-circuit in a full-wave SCR converter
(grid protection system does not operate)**

1. Three-phase voltage system
2. Grid impulse
3. Fault loop
4. Fault currents

In the case of the diode converter where there is no grid-control, the fault will always be a three-phase dc short circuit because there will always be three diodes under positive voltage at the moment when the fault occurs (see Figure 8-16). The short-circuit current and its non-damped peak magnitude are shown in Equation (8.22) and Equation (8.23):

$$i_{lsc} = I_m(1 + \cos \alpha) \quad (8.22)$$

$$i_{lpsc} = 2I_m \quad \text{at} \quad \alpha = 0 \quad (8.23)$$

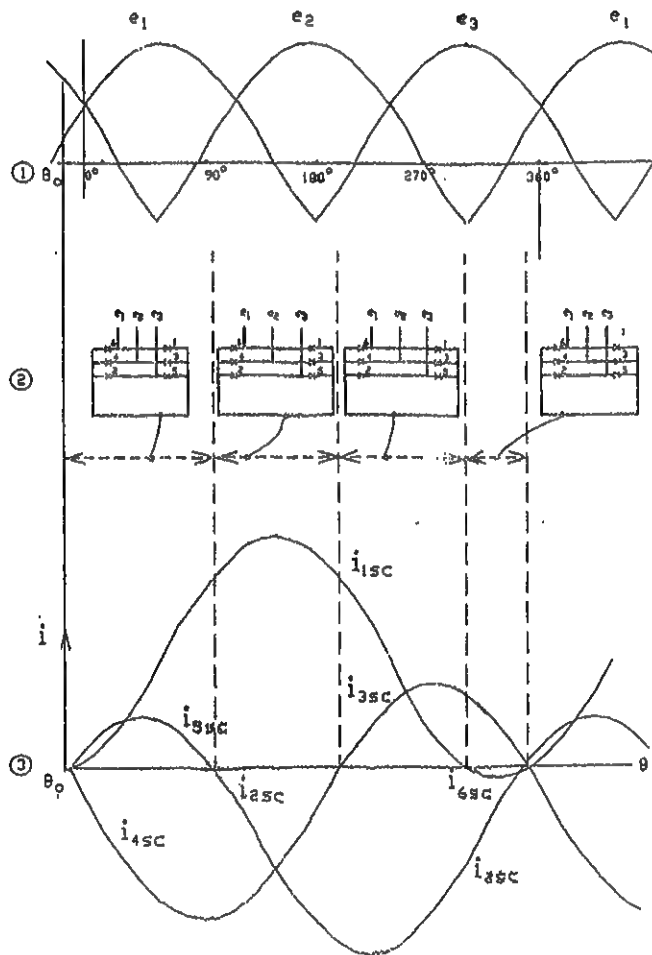


Figure 8-16—DC terminal short-circuit in the diode full-wave converter

1. Three-phase voltage system
2. Fault loops
3. Fault current

8.7 Arc-back short circuits

In an arc-back, one of the valves loses its semiconducting properties, forms a physical connection, and continues to conduct. Analysis of converter design and operating experience shows that arc-back or failure of semiconducting rectifiers are the most common faults of converter systems. The calculation of arc-back currents is, therefore, one of the important concerns in the theory and application of converter systems.

The greatest arc-back current occurs in a converter at no-load. In this state, both the three-phase half-wave and full-wave converters can be reduced to the circuit diagram of the half-wave converter shown in Figure 8-17.

If the grid-control protection system operates, the arc-back failure valve and the normal operating valve together form a two-phase dc short-circuit loop, Figure 8-18.

The current from the ac system to this dc short-circuit loop is shown in Equation (8.24):

$$i_{sc} = \frac{\sqrt{3}}{2} \times I_m \times (\cos \alpha - \cos \theta) \quad (8.24)$$

and the non-damped peak values of the current to the dc short circuit are shown in Equation (8.25) and Equation (8.26):

$$i_{psc} = \frac{\sqrt{3}}{2} \times I_m \times (1 + \cos \alpha), \alpha \neq 0 \quad (8.25)$$

$$I_{psc} = \sqrt{3} I_m, \alpha = 0 \quad (8.26)$$

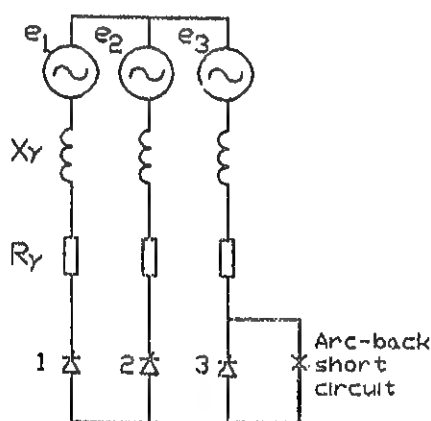


Figure 8-17—Three-phase converter circuit (no-load condition) with arc-back on phase 3

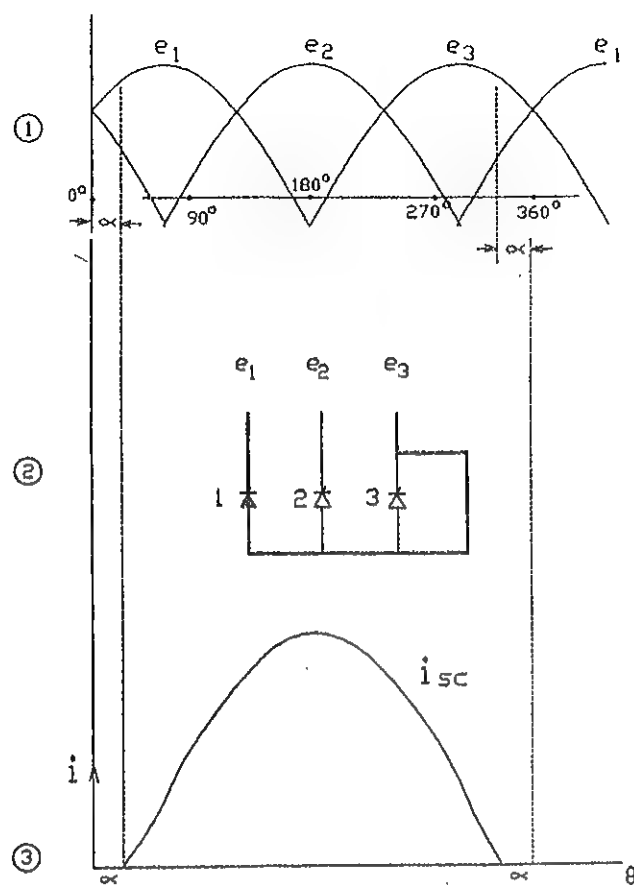


Figure 8-18—Arc-back short-circuit with operation of grid protection

1. Three-phase voltage system
2. Fault loop
3. Fault current

Since the grid pulses are stopped after the fault occurs, the duration of the short-circuit current is usually not more than one period. However, industrial experience with power converters has shown that sometimes a large arc-back short-circuit current causes another arc-back in the normally operating valve and the failure becomes an ac power frequency two-phase short circuit that is disconnected by a circuit breaker. This is known as a sequential arc-back.

If the grid-control protection system does not operate, the arc-back short-circuit current during the first 120° coincides with the arc-back current described above. After the initial 120° interval, a grid pulse is applied to the phase 2 valve and a three-phase short-circuit condition lasts for the duration of the first 360° period, see Figure 8-19. The current in the second 360° period will be larger than in the first since the initial fault current does not

equal zero at the beginning of the second cycle. Later on, the fault current reaches a steady state having the maximum amplitude. The conditions of current continuity for real converters are dependent on α , R , and ΔU , where ΔU is the voltage drop across the valve in the conducting mode. The fields of arc-back continuous current are shown in Figure 8-20, where $\Delta u = \Delta U/E_m$. The maximum current values are also dependent on α , R , and ΔU ; if two of these parameters are known, Figure 8-20 determines the third. Neglecting R and Δu , the τ for the current from the ac system to the arc-back dc short circuit is written in the simplified form shown in Equation (8.27):

$$i_{sc} = I_m(1 + 2 \times \cos(\alpha + 30^\circ)) \times \left(1 - \left(\frac{1}{4}\right)^n\right) \quad (8.27)$$

where n is the number of the period from the start of the fault.

The non-damped peak current, with $\alpha = 0$, is as shown in Equation (8.28):

$$I_{psc} = 2.73 I_m \quad (\text{Above the three-phase maximum peak}) \quad (8.28)$$

In the case of the diode converter, the arc-back process qualitatively is the same as described above for the case where the grid-control protection does not operate. However, the diodes start to conduct when their anode voltage becomes positive (at $0 = 30^\circ, 90^\circ$, and 210° ; see Figure 8-16), therefore for the calculations of the currents amplitudes it is necessary to take $\alpha = -30^\circ$. The arc-back continuous current is found using Figure 8-20. The maximum current occurs for $R = 0$, $\Delta u = 0$ and $\alpha = -30^\circ$. The dc short circuit is as shown in Equation (8.29):

$$i_{sc} = 3 I_m \left(1 - \left(\frac{1}{4}\right)^n\right) \quad (8.29)$$

The non-damped peak of the current to the diode converter arc-back is as shown in Equation (8.30):

$$I_{psc} = 3 I_m \quad (\text{Above the three-phase maximum peak}) \quad (8.30)$$

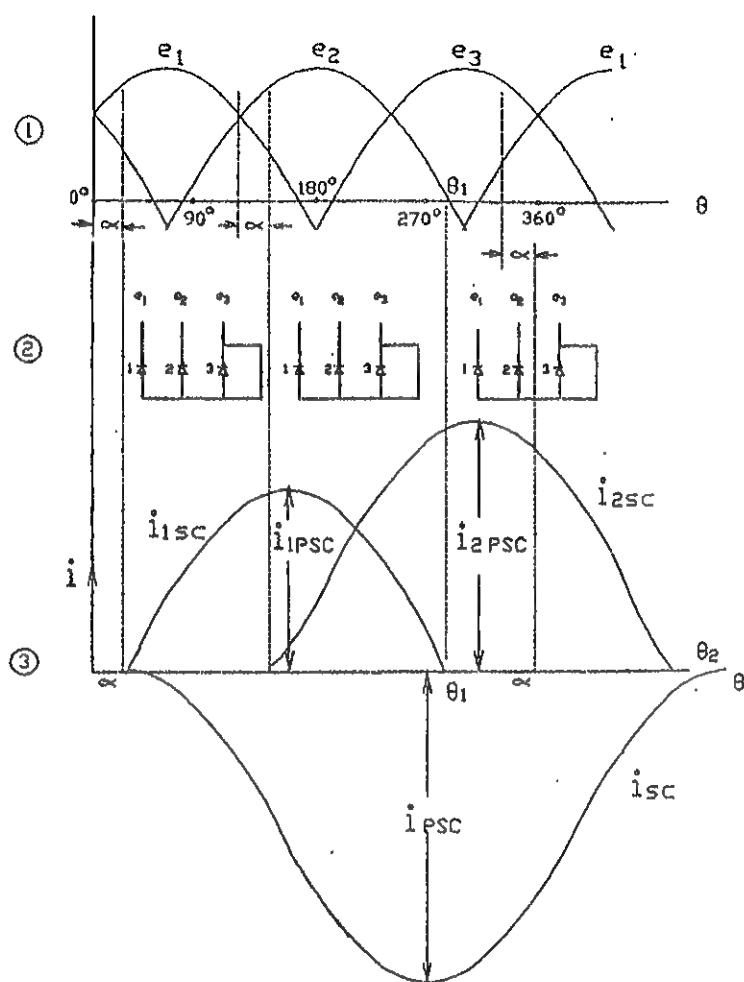


Figure 8-19—Arc-back short-circuit without operation of grid protection

1. Three-phase voltage system
2. Fault loops
3. Fault current

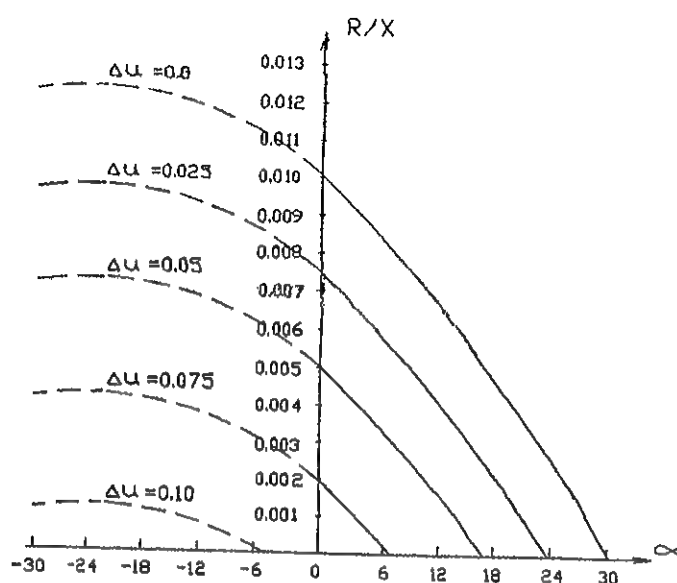


Figure 8-20—Fields of arc-back continuous currents, inter-relation of Δu , R/X , and α

8.8 Examples

The following are examples of calculations for the “typical” converter circuit of Figure 8-21. Data for the circuit is given below:

System voltage	$V_1 = 13.8$ kV, 60 Hz	Available short circuit	$S_{sc} = 500$ MVA
Rated transformer power	$S = 6.45$ MVA		
Primary voltage	$V_1 = 13.8$ kV		
Secondary voltage	$V_2 = 665$ V		
Transformer impedance	$Z_t = 8.5\%$		
Transformer X/R ratio	$X_t/R_t = 12$		
Converter filter resistance	$R = 0.0188$ ohms		
Converter filter inductance	$L = 1.28 \times 10^{-3}$ H		
DC motor drive power rating	6000 HP		
DC motor rated voltage	$U_d = 700$ V		
DC motor rated current	$I_d = 4830$ A		
DC motor rated speed	40/100 rev/m		
DC motor inductance	$L_m = 0.852 \times 10^{-3}$ H		
DC motor resistance	$R_m = 0.01248$ ohms at T_o		
Normal operating temperature	T_o		

Determining the parameters for the equivalent diagram:

- 1) $E_m = (\sqrt{2}/\sqrt{3}) \times V_2 = (\sqrt{2}/\sqrt{3}) \times 665 \text{ V} = 543 \text{ V}$ peak per phase [Equation (8.4)]
- 2) $X_s = V_1^2/S_{sc} = (13800)^2/(500 \times 10^6) = 0.38088 \text{ ohms}$ [Equation (8.2)].
Reflecting to 665 V.
 $0.38088 \times (665/13800)^2 = 0.000885 \text{ ohms}$ and corresponds to
 $L_s = X_s/2\pi f = 2.35 \times 10^{-6} \text{ Henry}$; R_s is assumed to be zero
- 3) $X_t = (Z_t/100) \times V_2^2/S = 0.085 \times (665)^2/6.45 \times 10^6 = 5.83 \times 10^{-3} \text{ ohms}$
[Equation (8.3)] corresponding $L_t = 1.55 \times 10^{-5} \text{ H}$; $R_t = X_t/12 = 4.86 \times 10^{-4} \text{ ohms}$
- 4) $X_y = X_s + X_t = 6.71 \times 10^{-3} \text{ ohms}$; $R_y = R_t$
- 5) $I_m = E_m/X_y = 543 \text{ V}/6.71 \times 10^{-3} \text{ ohms} = 80.87 \text{ kA}$
- 6) $X_y/R_y = 6.71 \times 10^{-3}/4.86 \times 10^{-4} = 13.82$, therefore the multiplying factor MF from Equation (8-7) = 1.804.
- 7) Parameters L , R , L_m , and R_m are given
- 8) $E_d = U_d + R_m \times I_d = 700 \text{ V} + 0.01248 \text{ ohms} \times 4830 \text{ A} = 760 \text{ V}$
- 9) Under normal operating conditions, the magnitude of phase ac rms current is equal to the dc current of 4830 A.

The locations of ac short circuits for the following example calculations are shown on Figure 8-21.

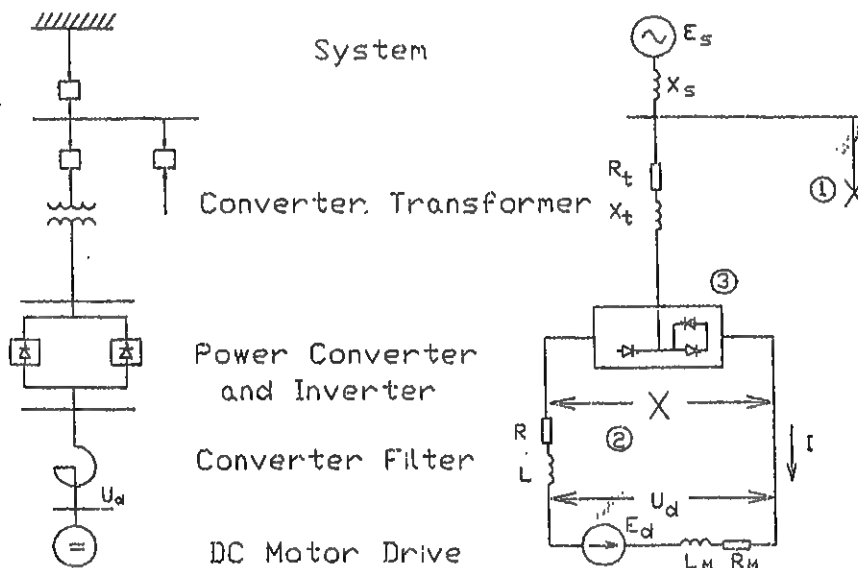


Figure 8-21—The example typical circuit and its equivalent diagram

Short-circuit locations are:

1. AC short circuit at 13.8 kV
2. DC short circuit at converter output
3. DC arc-back short circuit

Example 1. The first case is an ac short circuit on the 13.8 kV bus, assuming the dc motor has faster electrical transients than mechanical ones:

$$I_{\Sigma} = E_d / R_{\Sigma} \quad \text{Final maximum dc current [Equation (8.6)]}$$

where

$$E_d = 760 \text{ V}$$

$$R_{\Sigma} = 1.5 \times r_t + R + R_m \quad \text{for a system with a converter filter}$$

$$R_{\Sigma} = 1.5 \times R_t + R_m \quad \text{for a system without a converter filter (Table 8-1).}$$

a) For the system with a converter filter:

$$R_{\Sigma} = 1.5 \times 4.86 \times 10^{-4} + 1.88 \times 10^{-2} + 1.248 \times 10^{-2} = 3.20 \times 10^{-2} \Omega$$

$$I_{\Sigma} = \frac{760 \text{ V}}{3.20 \times 10^{-2} \Omega} = 23.75 \text{ kA} \quad \text{Final maximum dc current}$$

b) For the system without a converter filter:

$$R_{\Sigma} = 1.5 \times 4.86 \times 10^{-4} + 1.248 \times 10^{-2} = 1.321 \times 10^{-2} \Omega$$

$$I_{\Sigma} = \frac{760 \text{ V}}{1.321 \times 10^{-2} \Omega} = 57.54 \text{ kA} \quad \text{Final maximum dc current}$$

These steady-state ultimate currents will not be reached in an actual system because many factors impose practical limits, as noted in the text.

c) Combined ac system and dc contribution short-circuit currents:

To calculate a combined circuit breaker short-circuit duty at the 13.8 kV bus, Figure 8-21, the transient dc current at one-half cycle (of system frequency) is added to the ac first cycle peak short-circuit current. It is assumed that the converter has no filter [I_{Σ} and R_{Σ} from item b) above] and that the initial dc current $i(0)$ = dc machine rated current I_d = 4830 A. The inductive reactance corresponding to R_{Σ} is:

$$X_{\Sigma} = 1.5 \times 5.83 \times 10^{-3} + 2 \times \pi \times 60 \times 0.852 \times 10^{-3} = 0.330 \Omega/\text{phase}$$

$$\frac{X_{\Sigma}}{R_{\Sigma}} = \frac{0.330}{1.321 \times 10^{-2}} = 24.98$$

If two valves conduct, at two terminals of the converter transformer secondary wye winding, the half-cycle dc current [Equation (8.7)] is:

$$i_c = I_{\Sigma} - [I_{\Sigma} - i(0)] \times e^{-\pi/(X_{\Sigma}/R_{\Sigma})} = 57.54 - (57.54 - 4.83) \times e^{-\pi/24.98} = 11.06 \text{ kA}$$

It is further assumed that the transient dc current to the ac short circuit from the delta wound converter transformer primary terminals is transformed from the secondary by the turns ratio without distortion, and that a 1.15 multiplier applies for the highest 13.8 kV line of the three carrying dc contributions (as it does for a single phase secondary ac short circuit.) At 13.8 kV, the highest dc contribution is:

$$1.15 \times i_o \times \frac{V_2}{V_1} = 1.15 \times 11.06 \times \frac{665}{13800} = 0.61 \text{ kA}$$

For this example, the first cycle ac short-circuit duty at the 13.8 kV bus is 500 MVA with an X/R ratio of 24.3, calculated by procedures described earlier in this text. The first cycle symmetrical rms current is:

$$I_{\text{sym}} = \frac{500}{\sqrt{3} \times 13.8} = 20.92 \text{ kA}$$

The peak of the first cycle ac short-circuit current [Equation (8.7)] is:

$$\tau = 0.49 - 0.1 \times e^{-(X_E/R_E)/3} = 0.4897$$

$$I_{ac,peak} = I_{\text{sym},peak} [1 + e^{-2\pi\tau X_E/R_E}] = \sqrt{2} \times 20.92 \times [1 + 0.8842] = 55.75 \text{ kA}$$

Assuming the highest dc contribution through the inverting converter flows in the same direction in the same line as this ac peak current, the peak is increased to:

$$\text{Combined } I_p = 55.75 + 0.61 = 56.36 \text{ kA, a 1.1 percent increase}$$

d) Network equivalent circuit representation, for comparison:

The “equivalent circuit component” for representing the converter and dc motor in the ac system equivalent circuit for short-circuit calculations, has an impedance of 1/3 per-unit based on the ac three-phase apparent power input of the converter transformer at rated dc machine load and an X/R ratio of 10. It is assumed the transformer 6.45 MVA rating at 13.8 kV corresponds to the dc motor full load rating. The “equivalent circuit component” impedance converted to ohms at 13.8 kV is:

$$\begin{aligned} Z_c &= \left(\frac{0.333 \times 13.8^2}{6.45} \right) \cos(\tan^{-1}(10)) + j \sin(\tan^{-1}(10)) \\ &= 0.97930 + j9.79302 \Omega/\text{phase at 13.8 kV} \end{aligned}$$

The impedance representing the whole ac system developed from I_{sym} and X/R data is:

$$Z_s = \left(\frac{13.8}{\sqrt{3} \times 20.92} \right) (\cos(\tan^{-1}(24.3)) + j \sin(\tan^{-1}(24.3)))$$

$$= 0.01566 + j0.38053 \Omega/\text{phase at } 13.8 \text{ kV}$$

These impedances are paralleled to estimate the equivalent circuit first cycle peak short-circuit current. The resultant impedance is:

$$Z = 0.01566 + j0.36659 = 0.36693 \angle 87.524^\circ \Omega/\text{phase}$$

The equivalent circuit first cycle rms short-circuit current is:

$$I_{\text{sym}} = \frac{13.8}{\sqrt{3} \times 0.36693} = 21.71 \text{ kA} \quad X/R = 23.13$$

The calculated equivalent circuit first cycle peak short-circuit current [Equation (8.7)] is:

$$I_p = \sqrt{2} \times 21.71 \times 1.8755 = 57.58 \text{ kA}$$

This is 3.5 percent above the symmetrical current peak $I_{\text{acpeak}} = 55.75 \text{ kA}$ [from item c) above]. Compared with the corresponding composite ac + dc peak $I_p = 56.36 \text{ kA}$ [from item c)], the “equivalent circuit component” $I_p = 57.58 \text{ kA}$ calculation is definitely conservative in this example.

Example 2. The second case is a dc short circuit between the terminals of the full-wave converter:

- a) For an SCR bridge with grid-control protection where $\alpha = 0$, the peak current to the dc short circuit is [Equation (8.16)]. $I_m = 80.87 \text{ kA}$ from the parameters of the equivalent diagram.

$$I_{\text{psc}} = \frac{3 \times \sqrt{3}}{4} \times I_m = \frac{3 \times \sqrt{3}}{4} \times 80.87 = 105.05 \text{ kA}$$

or, taking into account the decay of the transient component ($\sin 30^\circ$) by using the multiplying factor of 1.804, yields the following equation:

$$I = \frac{\sqrt{3}}{2} \times I_m \times (1 + (1.804 - 1) \times \sin 30^\circ) = 98.19 \text{ kA}$$

- b) For an SCR bridge without grid-control protection where $\alpha = 0$, the peak current to the dc short circuit is [Equation (8.17)];

$$I_{psc} = \left(1 + \frac{\sqrt{3}}{2}\right) \times I_m = 1.866 \times 80.87 = 150.9 \text{ kA}$$

or, taking into account the multiplying factor of 1.804, yields:

$$I = \left(1 + (1.804 - 1) \frac{\sqrt{3}}{2}\right) \times I_m = 1.696 \times 80.87 = 137.18 \text{ kA}$$

c) For a diode bridge, the peak current to the dc short circuit is [Equation (8.23)]:

$$I_{psc} = 2I_m = 2 \times 80.87 = 161.74 \text{ kA}$$

or, taking into account the multiplying factor of 1.804, yields:

$$I = (1 + (1.804 - 1))I_m = 1.804 \times 80.87 = 145.89 \text{ kA}$$

Example 3.

The third case is an arc-back short circuit assuming $\Delta u = 0$:

a) For an SCR bridge with grid-control protection where $\alpha = 0$, the peak current to the dc short circuit is [Equation (8.26)]:

$$I_{psc} = \sqrt{3}I_m = 1.732 \times 80.87 = 140.07 \text{ kA}$$

b) For an SCR bridge without grid-control protection, with $\Delta n = 0$ and $R/X = 1/13.82 = 7.24 \times 10^{-2}$, the peak current to the dc short circuit is [Equation (8.27) with $\alpha = +10^\circ$ from Figure 8-20]:

$$I_{psc} = 2.53 \times I_m = 2.53 \times 80.87 = 204.60 \text{ kA}$$

Analyzing the results of the example calculations leads to the following conclusions:

- 1) The contribution of dc fault current to an ac short circuit from a dc machine through an inverting converter is relatively small, but it may be significant, and it may be dangerous due to the saturation of the isolating transformer core.
- 2) AC currents to converter dc short circuits may be very large.
- 3) Diode converter faults have the highest short-circuit currents.
- 4) Converter arc-backs and dc terminal short circuits are the most dangerous failures accompanied by the highest fault currents.
- 5) The maximum arc-back currents may be approximately 50% higher than those for the dc terminal short circuits.

8.9 Conclusions

For faults on the ac system, the dc system provides fault current:

- 1) When the dc system has a fault current source such as motors, batteries, or photo-voltaic cells.
- 2) When the converter operates as an inverter.
- 3) For the first cycle until the grid protection system operates and magnitude is approximately three times ($Z = 33\%$) the ac three-phase apparent power input of the converter transformer at rated dc machine load and an X/R ratio of 10.

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³IEEE publications are available from the Institute of Electrical and Electronics Engineers, 445 Hoes Lane, P.O. Box 1331, Piscataway, NJ 08855-1331, USA (<http://standards.ieee.org/>).

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Chapter 9

Calculating ac short-circuit currents in accordance with ANSI-approved standards

9.1 Introduction

This chapter outlines procedures for calculating short-circuit currents in three-phase ac systems according to the North American ANSI-approved standards, currently in effect. These procedures cover ac fault current decay from induction motors, synchronous motors and synchronous generators and apply to low and medium-voltage three-phase ac systems. Fault current dc decrement is also accounted for, in order to properly address the asymmetrical requirements of interrupting equipment:

Applicable ANSI-approved standards comprise the ANSI C37.5,¹ IEEE C37-010 addressing fault current calculating procedures for medium- and high-voltage three-phase ac systems, IEEE Std C37.13™ addressing fault current calculating procedures for lower voltage ac systems and the companion IEEE standards, IEEE Std 141™, IEEE Std 241™, and IEEE Std 242™.

This chapter focuses on calculating procedures yielding short-circuit currents for three-phase ac power systems in accordance with the above-mentioned guidelines, which are closely coupled to ANSI-related medium- and low-voltage interrupting equipment rating structures. Application and selection of interrupting equipment are covered in detail in Chapter 10.

Emphasis is given to three-phase faults and only occasional reference will be made to Single line-to-ground short circuits, whenever necessary, since a more exhaustive treatment of the subject of unbalanced short circuits is given in Chapter 11.

The sample one-line diagram used is, essentially, the same as the one used in previous chapters. It does, however, comprise, for the calculating and analytical requirements of this chapter, all sources of short-circuit currents.

9.2 Basic assumptions and system modeling

ANSI guidelines apply to low- and medium-voltage three-phase ac systems under the following assumptions:

- The ac system remains balanced and operates under constant frequency, which is the rated fundamental supply frequency.
- For the duration of the short circuit, there is no change in the source driving voltage(s) that caused the initial short-circuit current to flow.

¹Information on references can be found in 9.1.1

- Prefault load currents are neglected since they are assumed to be of much smaller magnitude than the short-circuit currents. As a consequence, prefault voltages, for fault current calculations purposes, are assumed to be the rated system voltages.
- Multivoltage systems are assumed to be coherent voltage level-wise. In other words, the transformation ratios for all transformers are assumed to be 1.00 and the transformer rated voltages are assumed identical to the system rated voltages.
- The fault impedance is zero; therefore, it has no current limiting effect.
- Contributions to the fault current from synchronous and induction motors vary in magnitude upon the inception of the short circuit and cannot be considered negligible.

In view of the above stated assumptions, quasi steady-state phasor analysis techniques, the utilization of a single driving voltage source at the fault point and the well-known computational framework of symmetrical components (Anderson [B1],² Blackburn [B2], Stevenson [B5], Wagner and Evans [B6]) constitute the analytical framework within which, ANSI-based short-circuit simulations are conducted. The analytical simplification of considering negative sequence impedances equal to positive sequence impedances is also adopted.

9.3 ANSI recommended practice for ac decrement modeling

9.3.1 General definitions and duty types

The term ac decrement reflects the natural tendency of short-circuit currents, contributed by rotating equipment, to decrease in magnitude upon the inception of the fault (Anderson [B1], Wagner and Evans [B6]). Synchronous machinery as well as induction motors exhibits the same qualitative behavior in the sense that their short-circuit currents decay with time from the onset of the short circuit. For analytical convenience, the ANSI-approved standards recognize three types of fault currents, associated with three distinct time periods.

- a) The “first cycle” currents, relevant up to and including one cycle immediately after the occurrence of the fault. These currents are deemed relevant for the so-called “first cycle” duty, often referred to as “momentary” or “closing and latching” duty. These currents are assumed to feature no ac decrement at all.
- b) The “interrupting” currents applicable to medium- and high-voltage circuit breaker parting times, relevant for the time period ranging from 1.5 to 4 cycles. These currents are deemed relevant for the so-called “interrupting” duty, also known as “breaking” duty. It is for these currents that ac decrement considerations become analytically relevant.
- c) The “steady-state” short-circuit currents relevant to times well beyond the opening time of medium-voltage circuit breakers, even with intentional time delay, falling within the time window of 30 cycles and beyond from the moment of the fault

²The numbers in brackets correspond to those of the bibliography in 9.12.

inception. These currents are deemed relevant for the so-called “time-delayed” duty that is why these currents are often called “time-delayed” currents.

9.3.2 Induction motor ac decrement modeling

Detailed performance analysis of induction machinery in the time domain can be fairly involved and, in its general form, employs two-axis reactance theory similar to the one adopted for synchronous machinery analysis (Anderson [B1]). For simplified, quasi-steady-state like short-circuit simulation purposes, however, the conventional modeling framework of time varying impedances driven by a constant voltage is quite adequate.

For induction motors, the locked-rotor impedance can be used, instead of the subtransient impedance for first cycle duty calculations. Calculations pertinent to the interrupting duty, accounting for ac decrement, use impedances higher than the locked-rotor impedance by applying multipliers, greater than unity, which are a function of machine type and size as portrayed in Table 9-1.

Differences between medium- and high-voltage (ANSI C37.5, IEEE Std C37.010™) and low-voltage (IEEE Std C37.13™) standards require, strictly speaking, two first cycle calculations and an interrupting calculation, as shown in the first two columns of Table 9-1. A convenient and desirable approach, however, for multivoltage systems is one that determines with reasonable conservatism the influences of both low- and high-voltage induction and synchronous motors, using only one network for first cycle current computations. A network combining the two similar, but different, networks of IEEE Std C37.13 and IEEE Std C37.010 is shown in column 3 of Table 9-1 (Huening [B3]).

Table 9-1—Rotating equipment reactances per IEEE Std C37.010 and IEEE Std C37.13—Induction motor $X'' = 16.7\%$

Source type	Medium- and high-voltage network IEEE Std C37.010	Low-voltage network per IEEE Std C37.13	Reactance for single multivoltage system IEEE Std C37.010/IEEE Std C37.13
Momentary OR first cycle calculations, 0–1 cycles			
Utility	X_s	X_s	X_s
Synchronous machines			
All turbo alternators, hydro with dampers and synchronous condensers	X''_d	X''_d	X''_d
Hydro without dampers	$0.75 X''_d$	$0.75 X''_d$	$0.75 X''_d$
Synchronous motors	X''_d	X''_d	X''_d
Large induction motors			

Table 9-1—Rotating equipment reactances per IEEE Std C37.010 and IEEE Std C37.13—Induction motor $X'' = 16.7\%$ (continued)

Source type	Medium- and high-voltage network IEEE Std C37.010	Low-voltage network per IEEE Std C37.13	Reactance for single multivoltage system IEEE Std C37.010/IEEE Std C37.13
Above 1000 HP	X''	X''	X''
Above 250 HP, 3600 r/min	X''	X''	X''
Medium induction motors			
All others, 50 Hp and above	$1.2 X''$	$1.2 X''$	$1.2 X''$ (see Note 1)
Small induction motors			
All smaller than 50 hp	\times	X''	$1.67 X''$ (see Note 2)
Interrupting time calculations, 1.5–5 cycles			
Utility	X_s	N/A	X_s
Synchronous machines			
All turbo alternators, hydro with dampers and synchronous condensers	X''_d	N/A	X''_d
Hydro without dampers	$0.75 X''_d$	N/A	
Synchronous motor	$1.5 X''_d$	N/A	$1.5 X''_d$
Large induction motors			
Above 1000 hp	$1.5 X''$	N/A	$1.5 X''$ (see Note 3)
Above 250 hp, 3600 r/min	$1.5 X''$	N/A	$1.5 X''$ (see Note 3)
Medium induction motors			
All others 50 hp and above	$3.0 X''$	N/A	$3.0 X''$
Small induction motors			
All smaller than 50 hp	\times	N/A	\times

Table 9-1—Rotating equipment reactances per IEEE Std C37.010 and IEEE Std C37.13—Induction motor $X'' = 16.7\%$ (continued)

Source type	Medium- and high-voltage network IEEE Std C37.010	Low-voltage network per IEEE Std C37.13	Reactance for single multivoltage system IEEE Std C37.010/IEEE Std C37.13
<p>NOTE 1—For larger size low-voltage induction motors, described as “medium > 50 hp, etc.,” using a contribution of “4.8 times rated current,” attributed in IEEE Std C37.13 to synchronous motors and considered also applicable to these induction motors, determines a 20.8% reactance. This is effectively the same as multiplying the 16.7% assumed reactance by approximately 1.2 as shown in column 2 of Table 9-1. For this motor group, therefore, there is reasonable correspondence of low and medium-voltage procedures.^a</p> <p>NOTE 2—For a typical induction motor, the subtransient reactance of 16.7% is determined by the initial magnitude of symmetrical root-mean-square (rms) current contributed to a terminal short circuit, assumed to contribute six times rated current. For smaller induction motors, “small < 50 hp” per Table 9-1, a conservative fault current estimate, according to IEEE Std C37.13 is “3.6 times rated current” (equivalent of 0.278 per-unit reactance). This is effectively the same as multiplying the 16.7% subtransient reactance by 1.67 as shown in column 3 of Table 9-1.</p> <p>NOTE 3—Large induction motors (> 1000 hp, 4-poles or more and >250 hp, 2-poles) are assumed to contribute six times their rated current to a terminal short circuit, when better data is not available. The corresponding 16.7% reactance is modified, per Table 9-1, depending on the calculation time. The same multipliers, however, apply if motor reactance data is known. For example, a 500 hp, 900-r/min motor with a known locked-rotor reactance of 15% would have a first cycle reactance of 18% or an interrupting time reactance 45%, (three times 15%).</p>			

^aNotes in text, tables, and figures are given for information only and do not contain requirements needed to implement the standard.

Using the approach of a single multivoltage level network, as outlined in Table 9-1, first cycle duty calculations for circuit breakers and fuses at both low and high voltages can be made with one set of network impedances.

It is important to emphasize at this point that accurate induction motor data for short circuit are paramount for simulation accuracy, particularly for industrial systems featuring a large content of induction motor loads. Motor data accuracy requirements are, as a rule, a function of the motor size. The best possible data should be sought for larger motors which also have the highest influence on calculated short-circuit duties. For small motor groups using first cycle reactance of 28% (0.28 p.u.) as typical is probably sufficiently conservative. Individual representation of large and medium motors (or separate groups of medium motors) is normally justified and increases confidence in the obtained results. It is recommended to consult the manufacturer for accurate locked-rotor current data (or first cycle reactances), whenever possible, to properly establish first cycle impedances before applying the impedance correction multipliers shown in Table 9-1 for interrupting duty simulations. For the cases in which induction motor contributions are critically important, additional data pertinent to motor time constants reflecting more exactly ac decrement characteristics for every machine may be justified. Higher-efficiency motors also feature

higher locked-rotor currents and therefore lower first cycle reactances. In the absence of exact data, informed engineering judgement must be used during the selection of assumed motor reactances, depending on the array of the induction motors present. Typical data for induction motor impedances as well as associated X/R ratios for short-circuit analysis can be found in IEEE Std 141 (*IEEE Red Book*).

9.3.3 Synchronous generator ac decrement modeling

Detailed analysis of synchronous machinery in the time domain requires machine reactances of the direct and quadrature axis (assuming the popular computational framework of two-axis reactance theory is used) as well as several time constants to properly reflect the necessary field and stator dynamics (Anderson [B1]). For simplified short-circuit simulation purposes, under the already assumed computational and modeling framework, the phenomenon of ac decrement can be conveniently modeled using time varying impedances driven by a constant field voltage.

ANSI C37.5 and IEEE Std C37.010 stipulate that direct axis reactances are sufficient for synchronous machines and rest on the utilization of the saturated subtransient and transient reactances. The subtransient impedances are primarily used for the first cycle calculation and are the basis for subsequent interrupting duty calculations.

Table 9-1 suggests no adjustment for the synchronous generator impedances for the interrupting calculations. This is deliberate because ac decrement for generators is accounted for in conjunction with dc decrement, as indicated in 9.4. Generator ac decrement modeling remains, however, conditional on the proximity of the generator to the fault. If a generator is electrically close to the short-circuit location its contribution is considered of the “local” type. If not, its contribution, and the generator, is considered as “remote.”

The criterion according to which synchronous generator contributions are classified as “local” or “remote” consists in comparing the magnitude of the actual generator contribution I_g , with the generator contribution I_t for a hypothetical three-phase fault at its terminals. If the ratio I_g/I_t is greater or equal to 0.4, the generator at hand is considered to be “local” with respect to the particular fault location. If this is not the case, the generator is classified as “remote” for the given fault location.

The same criterion can, equivalently, be quantified in terms of the generator subtransient impedance X''_d , as compared to the equivalent external impedance, Z_{ext} . According to this formulation, the generator contribution is considered “remote” if the ratio (Z_{ext}/X''_d) equals to or exceeds 1.5, assuming both impedances are expressed on the same MVA basis. Care, however, needs to be exercised in calculating Z_{ext} for non-radial systems.

9.4 ANSI practice for dc decrement modeling

Accounting for fault current asymmetry, requires proper consideration for the unidirectional fault current component of the short-circuit current. This unidirectional fault current component, often referred to as “dc-offset”, is due to the fact that current interruption in any inductive circuit cannot be instantaneous. The physics of inductive

current interruption (Wagner and Evans [B6]) dictates that, in general, a unidirectional current is present that decays exponentially with time upon the onset of the short circuit. The rate of decay of the dc-offset is closely related to the reactances and resistances of the supply system, while its initial value is solely dependent upon the exact moment of interruption. The total asymmetrical fault current whether quantified as first cycle currents immediately after the fault, or as interrupting fault currents sensed by a circuit breaker at contact separation, is directly dependent on the magnitude of this “dc-offset” and is instrumental in determining the electrical and mechanical capabilities of interrupting equipment for any voltage rating.

For multimachine systems of general configuration, more than one source contribute to the fault current through paths that are dependent on their location with respect to the fault position. Strictly speaking, therefore, the dc decrement characteristics of the fault currents are influenced by more than one X/R ratio. ANSI guidelines stipulate that, for computational convenience, system dc decrement characteristics can be safely quantified by a single X/R ratio, the X/R ratio at the fault position. This X/R ratio is to be calculated as the ratio of the equivalent system reactance with all resistances neglected, to the equivalent system resistance with all reactances neglected, both quantities calculated at the fault position. In other words, the equivalent system reactance seen from the fault location is to be calculated with a strictly reactive network and the equivalent system resistance is to be calculated with a strictly resistive network. It is for this reason that this technique is often referred to as the “separate X and R reduction” technique.

Note that it is also acceptable, per IEEE Std C37.010, to use the magnitude of the total complex equivalent impedance, Z instead of the total equivalent reactance at the fault point. The equivalent resistance, however, still needs to be obtained using a separate reduction of the resistive network. This is often referred to as the Z/R approach. The Z/R technique can be applied only if the same complex impedance used to calculate the X/R ratio was also used to calculate the fault current.

The X/R ratio calculated with the separate X and R reduction is not necessarily the same as the ratio of the imaginary to the real part of the complex network impedance at the fault point calculated using complex arithmetic. In general, the X/R ratio resulting from the separate X and R technique will be of higher magnitude, thus yielding a certain degree of conservatism.

ANSI first cycle fault currents, whether quantified in terms of “total asymmetrical” rms or “peak” amperes, are directly dependent on the fault point X/R ratio as determined from the first cycle network using either one of the above-stated techniques.

Similarly, interrupting currents calculated using procedures given in ANSI-approved standards, applicable to medium- and high-voltage circuit breakers, are quantified in terms of asymmetrical rms amperes and are dependent on the fault point X/R ratio, which now must be calculated from the interrupting network, using the interrupting network equipment impedances, according to Table 9-1. Furthermore, these interrupting currents are also very much dependent on the circuit breaker structure. More specifically, ANSI-approved standards distinguish between breakers rated on a total current basis, hereby referred to as “totally” rated breakers covered in ANSI C37.5 and breakers rated on a

“symmetrical” current basis, covered in IEEE Std C37.010, hereby referred to as “symmetrically” rated breakers.

Both rating structures, “total” and “symmetrical,” recognize the notion of “local” and “remote” sources of fault currents, with respect to the actual fault position. “Local” contributions reflect generating station contributions and are recognized according to the criterion stipulated in 9.3.

Both rating structures recommend applying multipliers to the symmetrical currents supplied by either source type to arrive at asymmetrical current estimates. Different multipliers are to be applied to the currents contributed from “local” sources as compared to the ones contributed by “remote” sources. These multipliers are a function of the rating structure, of the system X/R ratio, of the breaker interrupting speed as well as of the parting time. There is, however, one important difference. Interrupting fault currents calculated for “totally” rated breakers are actual short-circuit currents while interrupting currents calculated for “symmetrically” rated breakers are currents that are only to be compared with the symmetrical interrupting capabilities of these breakers.

The multipliers suggested by the so called “remote” curves are higher in magnitude as compared to the ones suggested by the so called “local” curves, because generator ac decrement is accounted for in the latter. In order, therefore, to avoid overestimating the magnitude of the asymmetrical fault current, by simply applying only the “remote” multiplier, it is recommended to consider a weighted-average between the “local” and the “remote” contents of the symmetrical fault current. The multiplier suggested by the “local” curves is applied to the “local” content of the symmetrical current while the “remote” multiplier is applied to the “remote” content, using the same fault point X/R ratio.

An alternative calculation, known as the “NACD ratio,” yields identical results and consists in applying a single composite multiplier to the symmetrical fault current magnitude. The term “NACD ratio” stands for “No AC Decay ratio” and is quantified as the “remote” content, of the symmetrical fault current, expressed in p.u. of the total symmetrical fault current. The multiplier to be applied to the total symmetrical fault current is calculated as follows:

- 1) Determine the “local” and “remote” multiplying factors, once the breaker rating structure, contact parting time and fault point X/R ratio is known.
- 2) Take the difference between “remote” and “local” multiplying factors.
- 3) Multiply this difference by the NACD ratio.
- 4) Add the above-calculated value to “local” multiplying factor.
- 5) If the resulting factor turns out to be less than 1.0, use 1.0.

Induction motor contributions can be considered as local for the purposes of this calculation, since enough conservatism is already embedded in the “local” decrement curves.

9.4.1 DC decrement curves for totally rated circuit breakers

The application of breakers of this rating structure is described in ANSI C37.5 and reflects an earlier breaker rating structure. When calculating interrupting currents conforming to this breaker rating structure, dc decrement is quantified by applying a “local” multiplier to the “local” content of the symmetrical fault current and a “remote” multiplier to the “remote” content of the symmetrical short-circuit current. These multipliers are a function of the fault point X/R ratio and the breaker contact-parting time and can be obtained from the curves illustrated in Figure 9-1. Figure 9-1a depicts the “remote” multipliers as a function of the fault-point X/R ratio and is applicable to both three-phase and line-to-ground faults. Figure 9-1b and Figure 9-1c depict the “local” multipliers for three-phase and line-to-ground faults respectively.

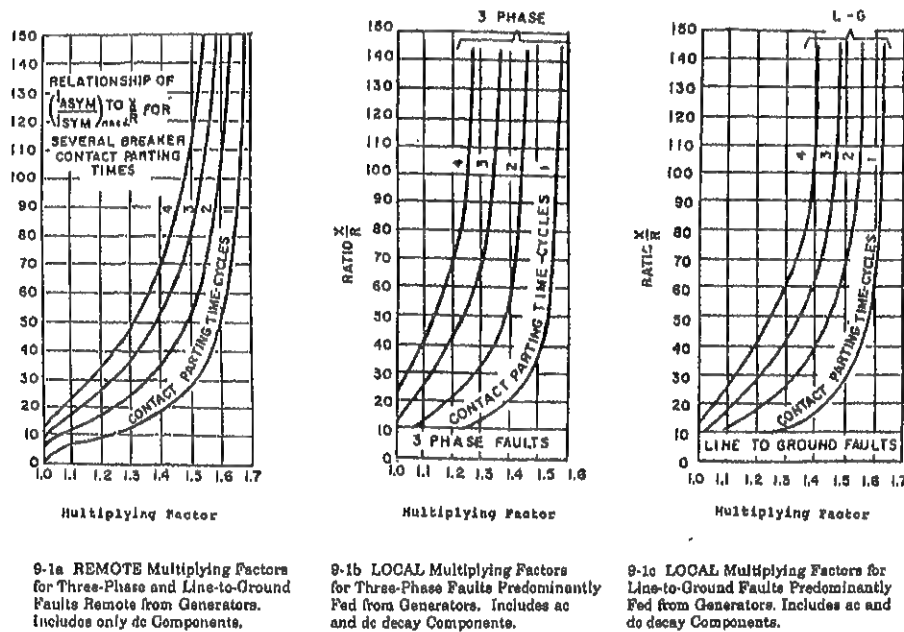


Figure 9-1—Multiplying factors for breakers rated on a total current basis

The curves are parameterized in terms of breaker contact-parting time but they can also be used in terms of breaker interrupting speed bearing in mind that, generally, a 3 cycle interrupting time breaker has a 2 cycle minimum contact parting time, a 5 cycle interrupting time breaker has a 3 cycle minimum contact parting time and a 8 cycle interrupting time breaker has a 4 cycle minimum contact parting time.

The multipliers described by the “remote” curves can be calculated analytically. Since this multiplier is the ratio of asymmetrical to symmetrical rms fault current, Equation (9.1) applies.

$$I_{asym}/I_{sym} = \sqrt{1 + 2e^{-4\pi C/(X/R)}} \quad (9.1)$$

where C is the breaker contact parting time in cycles at 60 Hz and the X/R is the system fault point X/R ratio at the same frequency.

No similar set of equations describes the “local” multipliers analytically, depicted in Figure 9-1b and Figure 9-1c. These multipliers must, therefore, be obtained directly from the curves; they can be estimated from points on the curves, or by curve fitting equations.

It is seen that different multipliers for the same X/R ratio are suggested depending on whether the fault contribution comes from a “local” or “remote” source for the case of three-phase faults. The same applies for line-to-ground faults. Both fault types however, share the same curves for “remote” sources. It is by virtue of the “local” curves that proper account is given to generator ac decrement, a factor that is not taken into account in the interrupting network (see also Table 9-1).

If the short circuit is predominantly fed from “remote” sources, the “remote” multiplier can be used for a conservative estimate. If the short-circuit current consists entirely of contributions from “local” sources, the “local” multiplier can be used instead. For fault currents exhibiting a hybrid extraction of both “local” and “remote” contributions, the weighted average of “local” and “remote” contents can be used as described above.

9.4.2 DC decrement applied to symmetrically rated breakers

The application of breakers following this rating structure is described in IEEE Std C37.010 and reflects a more recent rating structure. When calculating interrupting currents conforming to this breaker rating structure, accounting for dc decrement is also quantified by applying a “local” multiplier to the “local” fault current content and a “remote” multiplier to the “remote” fault current content of the symmetrical short-circuit current. These multipliers are, again, tabulated as a function of the fault point X/R ratio and the breaker contact parting time and are shown in the curves illustrated in Figure 9-2a, Figure 9-2b, and Figure 9-2c.

Figure 9-2a depicts the “remote” multiplying” factors and applies to both three-phase and line-to-ground faults. It is emphasized that it accounts solely for dc decrement. Different curves are given for various breaker speeds and each speed contains curves for various parting times.

Figure 9-2b and Figure 9-2c depict “local” multiplying factors for three-phase and line-to-ground faults respectively. They include the effects of both ac and dc decrement. Different curves are also given here for various breaker speeds and each speed contains curves for various parting times.

It is seen that these sets of curves contain more curves for explicit tabulation of intentional time delay for relatively higher breaker contact-parting times. Different multipliers, for the same X/R ratio, are also suggested for this rating structure depending on whether the fault contribution comes from a “local” or “remote” source for the case of three-phase faults or line-to-ground faults. It is by virtue of the difference in these curves that proper account is given to generator ac decrement, decrement that is not taken into account in the interrupting network (see also Table 9-1).

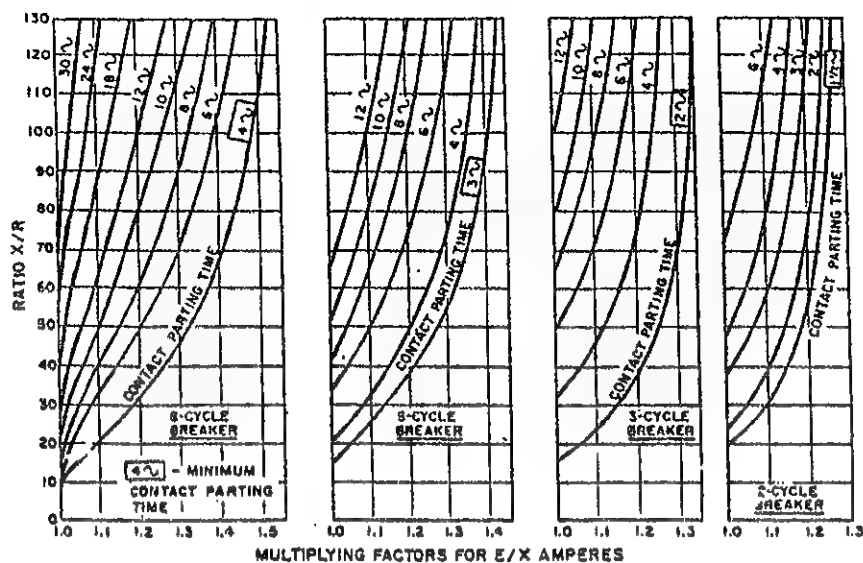


Figure 9-2a—REMOTE multiplying factors for symmetrically rated breakers. Three-phase and line-to-ground faults. Includes only dc decay component

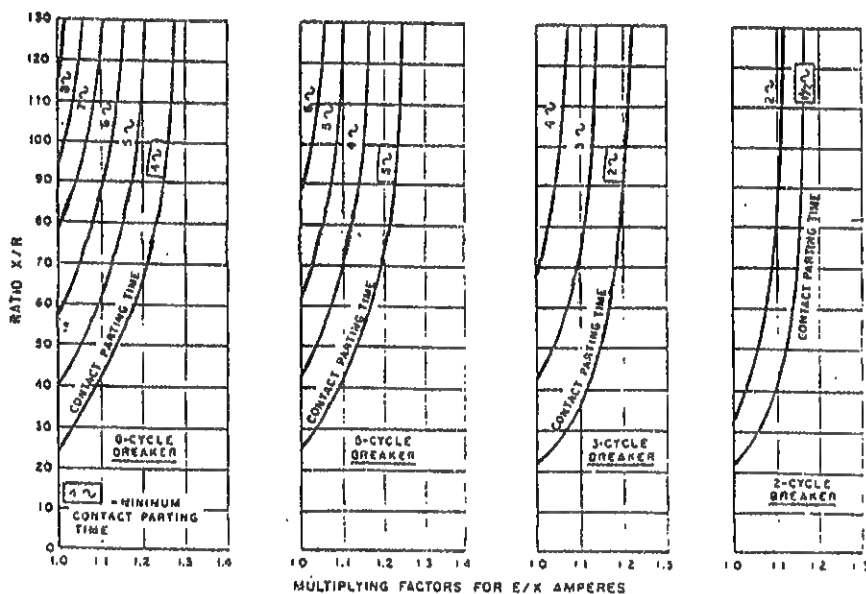


Figure 9-2b—LOCAL multiplying factors for symmetrically rated breakers. Three-phase faults predominantly fed from generators. Includes ac and dc decay components.

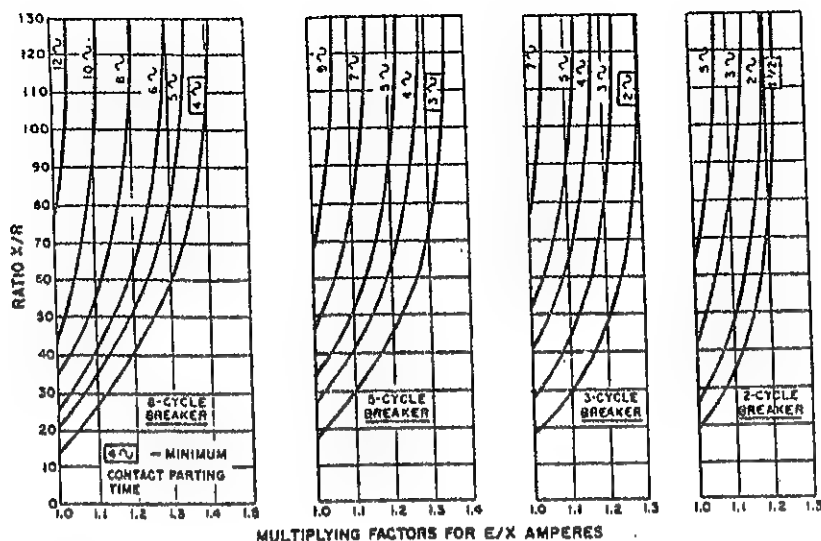


Figure 9-2c—LOCAL multiplying factors for symmetrically rated breakers. Line-to-ground faults predominantly fed from generators. Includes ac and dc decay components.

If the short-circuit current is predominantly fed from “remote” sources, the “remote” multiplier can be used for a conservative estimate. If the fault current is solely contributed by “local” sources, the “local” multiplier alone can be used instead. For fault currents exhibiting a hybrid extraction of both “local” and “remote” contributions, the weighted average of “local” and “remote” contents can be used as described in 9.3.

The difference between the rating structure of “symmetrically” versus “totally” rated breakers is that, per IEEE Std C37.010, the former have an embedded asymmetry factor, which quantifies the dc component of the short-circuit current at contact parting time, in terms of the total rms fault current, as follows in Equation (9.2).

$$I_{Totalrms} = I_{sym} \sqrt{1 + I_{dc}^2} \quad (9.2)$$

with I_{dc} expressed in p.u. of the symmetrical rms fault current, I_{sym} , at contact parting time. IEEE Std C37.010 assumes that a short circuit on any ac system can produce the maximum offset (dc component) of the current wave and quantifies this embedded asymmetry for the “symmetrically” rated breakers assuming an X/R ratio of 17 or, equivalently, a dc component decay governed by a L/R time constant of 45 ms for a 60 Hz system, per Figure 9-3. Similar decrement characteristics command a X/R ratio of 14 for a 50 Hz system.

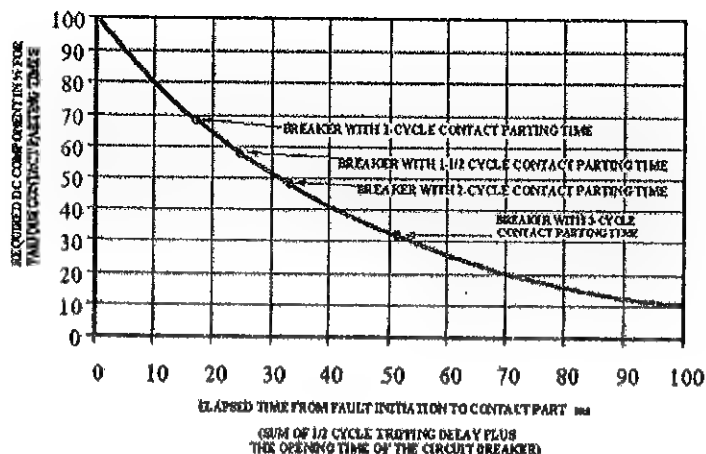


Figure 9-3—Power circuit breaker design requirements

Analytically, the dc component decay rate is given by the time constant, as the circuit L/R in seconds given by Equation (9.3):

$$T_{dc} = [Circuit X/R] / 2\pi f (Hz) \quad (9.3)$$

Therefore, the

$$\text{Required dc component in \% of ac component} = e^{-c/T_{dc}} \times 100$$

where c is the Contact Parting time expressed in ms. The dc component of the fault current is shown in Equation (9.4),

$$I_{dc} = [\%dc] X \sqrt{2} I_{sym} \quad (9.4)$$

These facts are also reflected in the differences between the magnitudes of multipliers used for “totally” or “symmetrically” rated breaker. In fact, multipliers obtained through Figure 9-2a, Figure 9-2b, and Figure 9-2c are, for similar breaker speeds and parting times, the multipliers one would obtain from Figure 9-1, Figure 9-b, and Figure 9-c after dividing them by the above-defined asymmetry factor.

It should be kept in mind that, notwithstanding the assumption of a X/R ratio equal to 17, a minimum relay time of 0.5 cycles is also assumed. According to IEEE Std C37.010, relaying times less than 0.5 cycles, excessive fault current motor contribution content, fault current delayed current zero crossings, and/or dc time constants exceeding 120ms for 60 Hz systems (X/R ratios higher than 45), require special considerations and/or consultation with the manufacturer.

When following the above calculation procedures, the calculated interrupting asymmetrical short-circuit currents can be directly compared with the interrupting capabilities of symmetrically rated circuit breakers. This convenience is, however, the reason that asymmetrical currents calculated using the so-called “symmetrical” sets of curves of this section do not reflect the true value of the total asymmetrical fault current.

9.5 ANSI-conformable fault calculations

One first cycle calculation and one Interrupting calculation are, in general, necessary, for the purposes of applying and sizing fault interrupting devices, according to ANSI-approved standards. Both calculations are to be performed on the same system single-line diagram. First cycle calculations are applicable to both low and medium to high-voltage systems while Interrupting calculations are only applicable to medium- and high-voltage systems and are closely related to breaker rating structure.

Occasionally, a third calculation needs to be performed the so-called “time-delayed” calculation. This type of analysis intends to assess fault currents within the time window that extends beyond six cycles from the fault inception and relates to current levels sensed by time-delayed relaying devices.

The necessary steps that need to be followed whenever ANSI-conformable short-circuit studies are to be undertaken are summarized in 9.5.1.

9.5.1 First cycle calculations

- 1) For momentary (first cycle) fault currents construct the first cycle network using source impedances per Table 9-1.
- 2) Reduce the network impedances, at the fault position, to a single R and then to a single X , using separate R and X network reductions respectively and calculate the fault point X/R ratio. An alternative option is to obtain the network equivalent resistance R from a separate R reduction and use the magnitude of the complex network impedance Z at the fault point, as resulted from complex network reduction, instead of using X . This method, also known as the “ Z/R method,” can be used provided the fault current was also calculated from the same network complex impedance Z . It is also permissible to consider as the fault-point prefault driving voltage, the exploitation (operating) voltage anticipated under actual service conditions, which could exceed the customarily assumed 1.00 p.u.
- 3) Calculate the symmetrical fault current by considering the equivalent impedance at the fault point to be the complex impedance Z , with real and imaginary parts the R and X calculated from the separate reductions, OR by using the magnitude of the equivalent complex network impedance Z at the fault point, as resulted from complex network reduction.
- 4) Use either “ R and X ” OR “ Z and R ,” to calculate the total asymmetrical rms and/or peak currents at the fault location.

First cycle peak currents used for applying present day high-voltage circuit breakers, some fuses and possibly to verify low-voltage circuit breaker capabilities can be calculated using the “Violet Book” equation (Chapter 2).

$$I_{peak} = \sqrt{2} I_{sym} (1 + e^{-2\pi\tau/(X/R)}) \quad (9.5)$$

where $\tau = 0.49 - 0.1e^{-(X/R)/3}$

Often, a peak multiplier of 2.6 is also used for simplicity when calculating duties of medium- and high-voltage circuit breakers above 1KV. Note that the recommended 2.6 “peak” factor assumes a X/R ratio of 17 and higher multipliers may result when larger X/R ratios are encountered.

First cycle asymmetrical rms short-circuit currents used for applying older high-voltage circuit breakers can be calculated using the “ANSI” equation (Chapter 2).

$$I_{asym} = I_{sym} \sqrt{1 + 2e^{-2\pi/(X/R)}} \quad (9.6)$$

The above-depicted equation, essentially, calculates total asymmetrical rms currents at 1/2 cycle. Often a multiplier of 1.6 is also used for simplicity when calculating duties of medium- and high-voltage circuit breakers above 1 kV. The recommended 1.6 “asymmetrical” multiplier, whenever used, implicitly assumes a fault point X/R ratio of 25. Again, higher X/R ratios may yield a multiplier higher than 1.6.

9.5.2 Interrupting calculations

- 1) For interrupting (1.5 to 5 cycles) fault currents construct the interrupting network using source impedances per Table 9-1
- 2) Reduce the network impedances, at the fault position, to a single R and then to a single X , using separate R and X network reductions respectively and calculate the fault point X/R ratio. An alternative option is to obtain the network equivalent resistance R and then use the magnitude of the complex network impedance Z at the fault point, as resulted from complex network reduction, instead of using X . This is the so-called Z/R method.
- 3) Calculate the symmetrical interrupting currents using a fault point equivalent impedance composed of R and X OR simply use Z . For a more conservative approach, one can use only X and neglect the resistance of the network. It is also permissible to consider as the fault- point prefault driving voltage, the exploitation (operating) voltage anticipated under actual service conditions, which could exceed the customarily assumed 1.00 p.u.
- 4) Classify the synchronous generator contributions as either “remote” or “local.” The classification of generator contributions is done according to the so-called “40% criterion” described in 9.3. According to this classification, the “local” and “remote” content of the total symmetrical fault current (NACD ratio) can therefore be estimated.

- 5) Adjust the calculated symmetrical short-circuit currents for dc and ac generating station decrement by applying the appropriate multipliers to the above calculated symmetrical rms currents, by taking into account the fault point X/R ratio as calculated per step 2) and the “local” as well as the “remote” content of the fault current, as calculated per step 4), taking into account breaker speed, breaker parting time and breaker rating structure, per 9.4. Generally speaking, the symmetrical fault current will feature both “local” and “remote” contents, particularly if in-plant generation is present. In this case, the technique of “weighted” interpolation, already outlined in 9.4 is advisable instead of using only “remote” multiplying factors. If the NACD ratio approach, for either “totally” or “symmetrically” rated breakers is used and the composite multiplier turns out to be less than unity, a value of 1.00 should be used. IEEE Std C37.010 allows for a simplified calculation when the fault currents have $X/R < 15$ and are less than 80% of the symmetrical interrupting rating of the equipment. In this case, the calculated E/X current is compared directly to the breaker rating.

Induction motor contributions can be considered as “local,” but if an extra degree of conservatism is desired it is also permissible to consider them as “remote.”

Generators modeling utility service-entrance points are considered to be of the “remote” type since, by default, they are assumed to feature no ac decrement.

9.5.3 Time delayed calculations

- 1) For this type of duty, the contributions of induction motors are considered inconsequential, since it is assumed that by that time they have decayed to zero. Accordingly, all induction motors are to be ignored for this type of calculations (see also Table 9-1). Only synchronous machines and passive system components like transformers, cables, lines, etc. are to be considered for the “time-delayed” network. Synchronous machines are accounted for, by virtue of their transient or larger impedances.
- 2) Reduce the “time delayed” network at the fault position to a single X , using only the reactance network.
- 3) Calculate the symmetrical interrupting currents using either E/X or E/Z where Z is, again, the magnitude of the complex equivalent impedance of the time delayed network at the fault point.

No dc decrement adjustment is needed for this type of calculation because it is assumed that enough time has elapsed for the unidirectional fault current component to have decayed to zero.

9.6 ANSI-approved standards and interrupting duties

9.6.1 General considerations

Fault interrupting devices must be applied so that they are capable of performing their intended function, i.e., interrupt the fault current at a given system location, without any

adverse effects for either the device itself or the system. Inability to interrupt the fault current can cause the interrupting device to fail and induce extensive damage to significant parts of the system with significant capital investment losses as well as unintended downtime and disconnection patterns. This section addresses concerns relevant to fault calculations but it should, in general, be born in mind that before applying or even selecting a fault current interrupting device, proper regard should be given to switching requirements, particular service conditions and insulation coordination-related aspects. In fact, quite often, it is the latter that will dictate interrupting equipment selection.

Short-circuit studies are also carried out for the purposes of setting over current protective devices. Depending on the device type, different short-circuit currents may be required, barring the fact that depending on the device acting time and purpose, different fault simulations may be warranted. As a rule, however, calculations based on the subtransient impedances are adequate.

9.6.2 Interrupting device evaluation aspects

A fundamental quantity when properly sizing fault current interrupting devices, is the fault current at the device location. Assuming that the relevant considerations for accounting for the worst-case prospective fault currents have been entertained, it is common practice to assess the interrupting device duties on the basis of fault currents for the nearest system bus. This is a realistic approach when there are a number of breakers connected around that bus. A feeder breaker connected to load centers with no motor load, or servicing a relatively small amount of motor load, would have little effect and the breaker duty would practically equal the bus duty. If the breaker capabilities are found to satisfy the total calculated bus duty, then the breaker is applied without any further consideration. The same rationale should also be applied to fused potential transformers on a bus since they will be subjected to the total bus fault current.

There are, however, cases where more detailed calculations may be warranted. Faults on major bus ties for instance, such as synchronizing buses, could demand more refined calculations for individual breaker duties. Similar considerations may apply to feeder breakers, depending on whether there is a significant downstream contribution.

In general, interrupting devices must be able to safely interrupt the prospective fault currents through them at the time they are called upon to operate. Medium- and high-voltage circuit breakers feature a delayed operation due to inherent (tripping mechanism) and/or intentional (relay acting time) time delay. Currents for evaluating interrupting requirements of medium- and high-voltage circuit breakers must be calculated according to the procedures outlined in 9.4 and 9.5 of this chapter, depending on the breaker rating structure. However, medium- and high-voltage circuit breakers still need to meet first cycle fault current requirements, quantified by the so called “momentary” or “closing and latching” breaker duties, in order to avoid exposing them to mechanical and thermal stresses that might seriously compromise their integrity and longevity.

9.6.3 First cycle currents

Medium- and high-voltage circuit breakers are applied using either the total rms or the peak current for the first cycle in order to ascertain that the so-called “momentary” or “closing and latching” requirements are met. Procedures for calculating first cycle currents have already been outlined in 9.5.

For low-voltage breakers, IEEE Std C37.13 makes a distinction between fused and unfused circuit breakers.

Fused low-voltage circuit breakers are evaluated on the basis of the total asymmetrical rms first cycle current. Due to the fact, however, that these breakers are rated on a symmetrical basis according to IEEE Std C37.13, there is already an embedded asymmetry assumed that rests on the assumption of a 20% test power factor, equivalent to a test fault point X/R ratio of 4.9. This necessitates a further calculation for the breaker duty only when power factors smaller than 20% (X/R ratios greater than 4.0) are encountered. First cycle asymmetrical currents can be calculated, per IEEE Std C37.13, according to the Equation (9.7):

$$I_{asym} = I_{sym} \sqrt{1 + 2e^{-2\pi/(X/R)}} \quad (9.7)$$

Unfused low-voltage circuit breakers need to be evaluated on the basis of first cycle peak currents. Due to the fact, however, that these breakers are rated on a symmetrical basis according to IEEE Std C37.13, there is already an embedded asymmetry assumed that rests on the assumption of 15% test power factor, equivalent to a test fault point X/R ratio of 6.6. This necessitates a further calculation for the breaker duty only when power factors smaller than 15% (X/R ratios greater than 6.6) are encountered. First cycle peak currents can be evaluated, per IEEE Std C37.13, according to Equation (9.8):

$$I_{peak} = I_{sym} \sqrt{2(1 + e^{-\pi/(X/R)})} \quad (9.8)$$

9.7 One-line diagram layout and data

The raw data for the system equipment, the per unitized data and the One-line diagram of the sample system to be used is shown in Chapter 1. However, the single-line diagram to be used here is supplemented by assuming all the induction motors connected. Furthermore, two generators at buses 04:MILL-2 and 50:GEN1, and a large synchronous motor at bus 08:M-FDR-L are also considered to be in service.

Both utility service entrance transformers are operational and the bus tie between their primary buses 1 and 2 (69 kV) is considered open. So is the bus tie between the synchronizing bus bars 3 and 4 (13.8 kV). Cable runs between buses 9 (FDR E) and 13 (T6PRI), 28(T10 SEC) and 38(480 TIE), 30 (T12 SEC) and 38(480 TIE), 10(EMER) and 12(T5PRI) are also considered open. The two 2000 kvar shunt capacitors located at bus bars 3:MILL-1 and 4: MILL-2 respectively, are ignored.

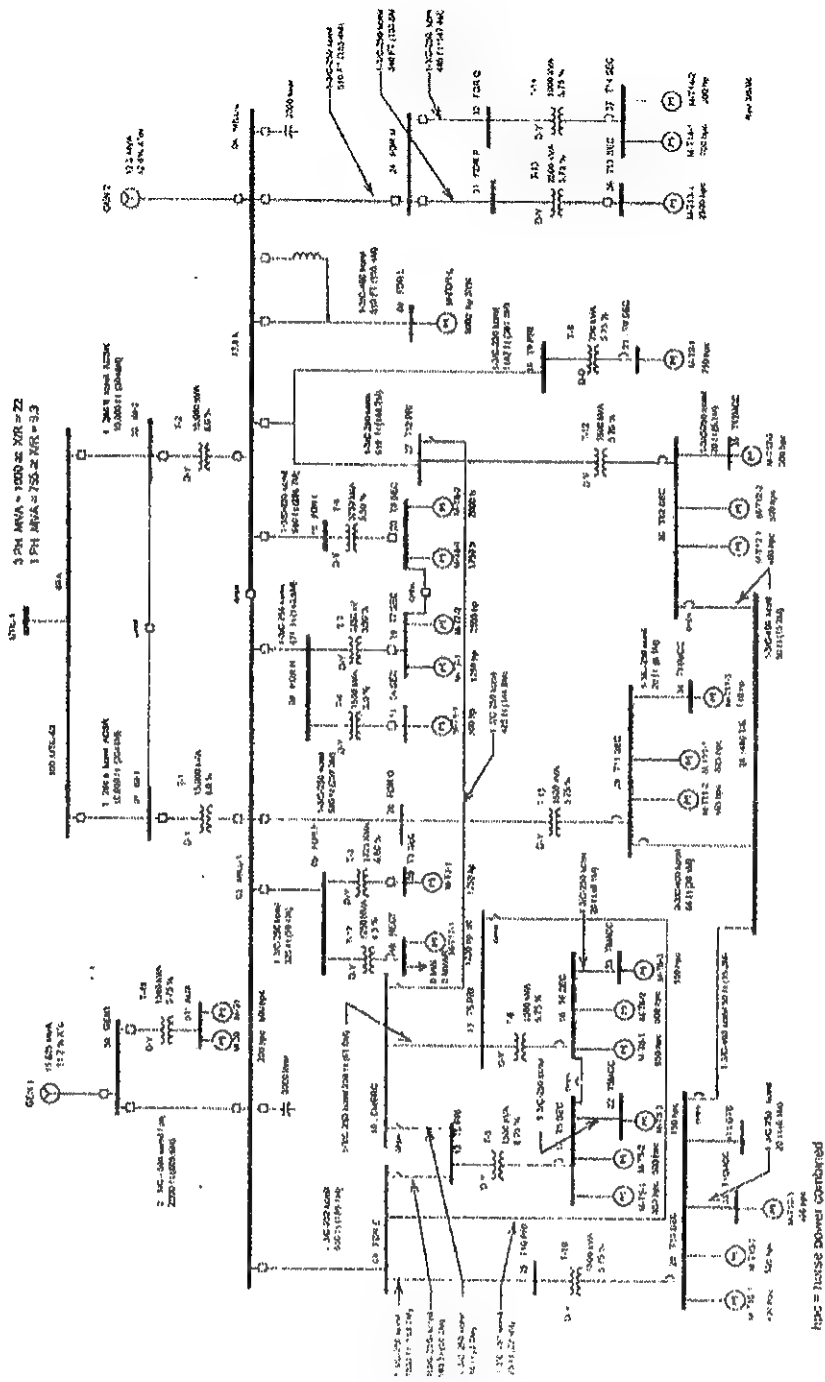


Figure 9-4—System one-line diagram for sample calculations

In what follows, sample calculations and results for first cycle (momentary) and interrupting duty calculations are illustrated. Static network plant, utility and generators remain identical, impedance-wise, for both simulations. Synchronous and induction motor impedances, however, do vary according to Table 9-1. For clarity, Table 9-2 shows the impedance values considered for all motors in the system for both first cycle and interrupting calculations.

**Table 9-2—Motor impedances for momentary and interrupting duty
(p.u., 10 MVA)**

Motor bus #	Bus kV	Motor type	Motor MVA	Motor impedances			
				R_{mom}	X_{mom}	R_{inter}	X_{inter}
11	2.40	IM	0.4750	0.352	4.219	0.879	10.547
17	0.48	IM	0.8242	0.338	3.380		
17	0.48	IM	0.5000	0.802	4.008	2.004	10.020
18	0.48	IM	0.8242	0.338	3.380		
18	0.48	IM	0.5000	0.802	4.008	2.004	10.020
19	2.40	IM	1.1250	0.057	1.484	0.085	2.227
19	2.40	IM	2.3750	0.047	0.703	0.070	1.055
20	2.40	IM	1.6625	0.067	1.005	0.100	1.507
20	2.40	IM	1.8000	0.060	1.556	0.090	2.333
21	0.48	IM	0.7273	0.320	3.831		
22	0.48	IM	0.1425	1.398	19.571		
23	0.48	IM	0.1425	1.398	19.571		
28	0.48	IM	0.5000	0.697	6.972		
28	0.48	IM	0.4000	0.802	4.008	2.004	10.020
29	0.48	IM	0.6250	0.321	3.206	0.802	8.016
29	0.48	IM	0.4650	1.199	5.998		
30	0.48	IM	0.3879	0.431	5.166	1.077	12.916
30	0.48	IM	0.5000	1.116	5.578		
33	0.48	IM	0.2875	0.807	9.684		
34	0.48	IM	0.1100	3.621	25.354		
35	0.48	IM	0.2875	0.807	9.684		
36	2.40	IM	2.2500	0.025	0.818	0.062	2.045

**Table 9-2—Motor impedances for momentary and interrupting duty
(p.u., 10 MVA) (continued)**

Motor bus #	Bus kV	Motor type	Motor MVA	Motor impedances			
				R_{mom}	X_{mom}	R_{inter}	X_{inter}
37	0.48	IM	0.6788	0.246	2.952	0.615	7.381
37	0.48	IM	0.3000	1.859	9.296		
39	4.16	IM	1.6625	0.034	1.005	0.051	1.507
49	0.48	IM	1.2500	0.264	2.640		
51	0.48	IM	0.2000	1.432	10.020	3.579	25.050
51	0.48	IM	0.5700	0.408	4.893		
8	13.80	SM	9.0000	0.006	0.222	0.010	0.333

9.8 First cycle duty sample calculations

First cycle duty ANSI-compatible calculations will be illustrated for buses 04:MILL-2, 8:FDR L and 37:T14 sec. Both symmetrical as well as asymmetrical current calculations are shown for illustration. First cycle asymmetrical currents are to be calculated according to the procedures given in 9.5. Table 9-2 shows the rotating equipment impedances used for both first cycle (“momentary”) and interrupting duty simulations.

9.8.1 First cycle duty calculations at bus 4:MILL-2

Fault current and equivalent impedance at fault location

For a fault on the 13.8 kV bus 04: MILL-2 the total Thevenin equivalent bus impedance can be determined using either manual calculations employing successive network reduction techniques or by means of a computer. Complex arithmetic becomes rapidly intractable for hand-calculations, thus for all subsequent illustrations the results were generated by computer. It suffices to say, on a qualitative basis, that the total fault impedance to bus 04:MILL-2 is affected by the motors connected at buses 03:MILL-1 and 04:MILL-2. The synchronous generator connected at bus 03:MILL-1, reduces further the equivalent impedance.

The equivalent complex impedance at bus 4:MILL-2 is,

$Z_{eq} = 0.0017 + j 0.0301$ p.u., on 10 MVA and 13.8 kV (line-to-line). This impedance gives, for a prefault voltage of 1.00 p.u. (13.8 kV line-to-line)

$I_{3-ph} = 1.00/Z_{eq} = 33.1971$ p.u. at -86.74 degrees OR $I_{3ph} = 13\ 889$ amperes,

while the separate X and R reductions yielded an X/R ratio of 22.363. This ratio is calculated as the ratio of total equivalent reactance of 0.030 p.u. as calculated from the reactance network and the total equivalent resistance of 0.00134 p.u. as calculated from the resistance network. Note that if the X/R were calculated from the equivalent complex impedance the result would have been 17.70 ($= 0.0301/0.0017$).

First-ring fault current contributions for a fault at 4:MILL-2

Table 9-3 illustrates the composition of the total fault current at bus 4:MILL-2 as contributions from the buses located one-bus away from the fault location.

Table 9-3—First ring contributions for a fault at bus 4:MILL-2 (first cycle)

From bus	Current (p.u.)	Current (A)	Angle (deg)	Fault MVA
2:69-2	15.2533	6381	-85.66	153
15:FDR I	1.3157	550	-86.35	13
16:T9 PRI	0.2170	91	-84.12	2
24:FDR M	1.3038	545	-86.05	13
27:T12 PRI	0.8788	367	-82.13	9
8:FDR L	4.4792	1874	-88.15	45
GEN2	9.7618	4084	-88.40	97.6

Asymmetrical first cycle fault currents

For X/R ratios calculated according to ANSI-procedures following separate X and R reductions, Table 9-4 depicts the first cycle currents at bus 4:MILL-2 that can be quantified as either total asymmetrical rms or peak currents.

Table 9-4—First cycle asymmetrical currents at bus 4:MILL-2

Bus 4:MILL-2, first cycle ANSI $X/R=22.363$	$I_{\text{sym}} = 13\,889\text{ A}$
Total 1/2 cycle asymmetrical rms, per 1.6 multiplier	$I_{\text{asym}} = 22\,2205\text{ A}$
Total 1/2 cycle asymmetrical rms, per ANSI equation	$I_{\text{asym}} = 22\,000\text{ A}$
Peak current based on 2.6 multiplier	$I_{\text{peak}} = 36\,110\text{ A}$
Peak current, per "Violet book" equation (2.644 multiplier)	$I_{\text{peak}} = 36\,730\text{ A}$

9.8.2 First cycle duty calculations at bus 8:FDR L

Fault current and equivalent impedance at fault location

For a fault at the 13.8 kV bus 8:FDR L, the equivalent complex impedance reads as follows:

$Z_{eq} = 0.0023 + j 0.0307$ p.u., on 10 MVA and 13.8 kV (line-to-line). This impedance gives, for a prefault voltage of 1.00 p.u. (13.8 kV line-to-line)

$I_{3-ph} = 1.00/Z_{eq} = 32.4356$ p.u. at -85.80 degrees OR $I_{3ph} = 13\ 570$ amperes,

while the separate X and R reductions yielded an X/R ratio of 17.513. This ratio is calculated as the ratio of total equivalent reactance of 0.031 p.u. (as calculated from the reactance network) and the total equivalent resistance of 0.00177 p.u. (as calculated from the resistance network). Note that if the X/R were calculated from the equivalent complex impedance the result would have been 13.35 ($= 0.0307/0.0023$).

First-ring fault current contributions for a fault at 8:FDR L

Table 9-5 illustrates the composition of the total fault current at bus 8:FDR L as contributions from the bus 4:MILL-2 and the 9 MVA synchronous motor M-FDR-L connected directly at the bus.

Table 9-5—First ring contributions for a fault at bus 8:FDR L

From bus	Current (p.u.)	Current (A)	Angle (deg)	Fault MVA
4:MILL-2	27.9426	11690	-85.40	279
MOTOR	4.4981	1882	-88.34	45

Asymmetrical first cycle fault currents

For X/R ratios calculated according to ANSI-procedures following separate X and R reductions, Table 9-6 depicts the first cycle currents at bus 8:FDR L that can be quantified as either total asymmetrical rms or peak currents.

Table 9-6—First-cycle asymmetrical currents at bus 8:FDR L

Bus 8:FDR L, first cycle ANSI $X/R=17.513$	$I_{sym} = 13.57$ KA
Total 1/2 cycle asymmetrical rms, per 1.6 multiplier	$I_{asym} = 21.71$ KA
Total 1/2 cycle asymmetrical rms, per ANSI equation	$I_{asym} = 21.01$ KA

Table 9-6—First-cycle asymmetrical currents at bus 8:FDR L

Peak current based on 2.7 multiplier	$I_{\text{peak}} = 35.28 \text{ KA}$
Peak current, per "Violet book" equation (2.598 multiplier)	$I_{\text{peak}} = 35.26 \text{ KA}$

9.8.3 First cycle duty calculations at bus 37:T14 SEC

Fault current and equivalent impedance at fault location

For a fault at the low-voltage bus 37:T14 SEC, the equivalent complex impedance reads as follows:

$$Z_{\text{eq}} = 0.0776 + j 0.4726 \text{ p.u., on 10 MVA and 13.8 kV (line-to-line)}$$

This impedance gives, for a prefault voltage of 1.00 p.u. (13.8KV line-to-line)

$$I_{3\text{-ph}} = 1.00/Z_{\text{eq}} = 2.088 \text{ p.u. at } -80.68 \text{ degrees OR } I_{3\text{ph}} = 25 \text{ 115 amperes,}$$

while the separate X and R reductions yielded an X/R ratio of 6.607. This ratio is, again, calculated as the ratio of total equivalent reactance of 0.472 p.u. (as calculated from the reactance network) and the total equivalent resistance of 0.0714 p.u. (as calculated from the resistance network). Note that if the X/R were calculated from the equivalent complex impedance the result would have been 6.09 ($= 0.4726/0.0776$).

First-ring fault current contributions for a fault at 37:T14 SEC

Table 9-7 illustrates the composition of the total fault current at bus 37:T14 SEC as contributions from the bus 32:FDR Q and the induction motors directly connected at this bus.

Table 9-7—First ring contributions for a fault at bus 37:T14 SEC

From bus	Current (p.u.)	Current (A)	Angle (deg)	Fault MVA
37:T14 SEC	1.6462	19801	-79.87	16
M-T14-2	0.1055	1269	-78.69	1
M-T14-1	0.3376	4060	-85.24	3

Asymmetrical first cycle fault currents at 37:T14 SEC

For X/R ratios calculated according to ANSI-procedures following separate X and R reductions, Table 9-8 depicts the first cycle currents at bus 37:T14 SEC that can be quantified as either total asymmetrical rms or peak currents.

Table 9-8—First cycle asymmetrical currents at bus 37:T14 SEC

Bus 37:T14 SEC, first cycle ANSI $X/R = 6.607$	$I_{\text{sym}} = 25,115 \text{ A}$
Total 1/2 cycle asymmetrical rms, per ANSI equation	$I_{\text{asym}} = 33,439 \text{ A}$
Peak current per "Violet book" equation	$I_{\text{peak}} = 58,042 \text{ A}$

From the above-illustrated results, it is seen that the separate X/R reduction yields a larger fault-point X/R ratio, something that is to be expected in most practical applications. It is also seen that the complex network reduction, for the same buses, results in a slightly higher resistance as compared to the resistance calculated from the separate R reduction, while the reactance values remain comparable. These patterns are consistent with regularly observed practice, and found to be typical with ANSI-calculated X/R ratios.

It is also seen that both total half-cycle asymmetrical rms and peak currents are quite sensitive to the X/R ratio. In fact, lower asymmetrical current estimates would have been obtained if lower X/R ratios had been used. Furthermore, using the 1.6 and 2.6 multipliers for a quick estimation of total 1/2 asymmetrical rms and peak currents respectively can be non-conservative for some cases.

9.9 Interrupting duty sample calculations

In this subclause, interrupting duty ANSI-compatible calculations will supplement the first cycle simulations performed for buses 04:MILL-2 and 8:FDR L. Symmetrical and asymmetrical short-circuit currents calculations are shown for illustration.

First cycle calculations suffice for bus 37:T14 SEC, since low-voltage interrupting equipment rating structures for instantaneously-acting devices like fuses and LVCBs equipped with instantaneous elements do not necessitate dedicated interrupting duty calculations. If the low-voltage breakers, however, had short time trips without an instantaneous trip element, then an extended time or '30 cycle' fault calculation should be made if the first cycle fault current is over the breaker short time rating.

9.9.1 Interrupting duty calculations for bus 4:MILL-2

Equivalent impedance, fault current and fault MVA at fault location

$Z_{\text{eq}} = 0.0019 + j 0.0337 \text{ p.u.}$, resulting in a symmetrical rms three-phase fault current of 12 407 amperes with an angle of -86.85 degrees for a prefault voltage of 1.00 p.u. (13.8 kV line-to-line). For this current, the three-phase fault MVA level is found to be 297 MVA.

X/R ratio and impedances

The separate X and R reduction resulted in an equivalent reactance $X_{\text{eq}} = 0.034 \text{ p.u.}$ and an equivalent resistance of 0.00149 p.u. , thus yielding an X/R ratio of 22.8 ($= 0.034/0.00149$)

First-ring contributions

From bus 2: 69-2	6376 amperes at an angle of -85.67 degrees
From bus 15:FDRI	393 amperes at an angle of -86.49 degrees
From bus 16:T9 PRI	0.0 amperes at an angle of 0.00 degrees
From bus 24: FDR M	236 amperes at an angle of -87.13 degrees
From bus 27:T12 PRI	71 amperes at an angle of -81.55 degrees
From bus 8:FDR L	1251 amperes an angle of -88.21 degrees
From generator GEN2	4084 amperes at an angle of -88.40 degrees

Generator contribution classification

Once the contributions have been calculated, the synchronous generator contributions need to be classified as either “local” or “remote”. The following table illustrates the classification process according to the 40% criterion, as outlined in 9.4. Next to the p.u. contribution of every generator is also shown in parenthesis the comparison threshold according to which the classification is made. The threshold, for every generator, is 40% of the fault current one would obtain if the generator terminals were boldly faulted.

According to Table 9-9, the fault current featuring no ac decrement is approximately 15.082 p.u (14.073 + 1.009 p.u), amounting to 50.855% of the total fault current. Computer calculations taking into account vectorial arithmetic yielded a total of 50.90%, amounting to a NACD content of 0.509. All motor contributions were considered “local” for this calculation.

Table 9-9—Generator contribution classification for fault at 4:MILL-2

Fault at bus 4:MILL-2	Fault current (p.u.) 29.6564
Current from Utility (Remote)	14.073 p.u. (by definition)
Current from GEN1 (Remote)	1.009 p.u. (< 5.5784 p.u)
Current form GEN2 (Local)	9.762 p.u (> 3.9048 p.u)

Calculation of asymmetrical currents for totally rated breakers

Let us assume for illustration that a 5-cycle totally rated breaker is to be applied. Assuming a breaker contact parting time of 3 cycles, for a fault point X/R ratio of 22.797, one obtains for a three-phase fault a “remote” multiplier of 1.175 and a “local” multiplier of 1.07 from Figure 9-1a and Figure 9-1b respectively. We therefore, obtain the following:

$$I_{\text{asym}} = 12\,407 (1.175) = 14\,578 \text{ A (remote multiplier only)}$$

$$I_{\text{asym}} = 12.407 (0.491)(1.07) + 12\,407(1.175)(0.509) = 13\,939 \text{ A (weighted)}$$

And following the equivalent NACD ratio approach:

$$12\,407 [(1.175 - 1.07)(0.509) + 1.07] = 13\,939 \text{ amperes}$$

Calculation of asymmetrical currents for symmetrically rated breakers

Let us assume for illustration that a 5-cycle symmetrically rated breaker is to be applied. Assuming, again, a breaker contact parting time of 3 cycles, for a fault point X/R ratio of 22.797, one obtains for a three-phase fault a “remote” multiplier of 1.068 and a “local” multiplier of 1.00, see Figure 9-2a and Figure 9-2b respectively. We therefore, obtain the following:

$$I_{\text{asym}} = 12\,407 (1.068) = 13\,251 \text{ A (remote multiplier only)}$$

$$I_{\text{asym}} = 12.407 (0.491)(1.00) + 12\,407(1.068)(0.509) = 12\,836 \text{ A (weighted)}$$

And following the equivalent NACD ratio approach:

$$12\,407 [(1.068-1.00)(0.509) + 1.00] = 12\,836 \text{ amperes}$$

9.9.2 Interrupting duty calculations for bus 8:FDR L

Equivalent impedance, fault current, and fault MVA at fault location

Complex network reduction for bus 8:FDR E yielded an equivalent complex impedance of $Z_{\text{eq}} = 0.0024 + j\,0.0344$ p.u., resulting in a symmetrical rms three-phase fault current of 12 130 amperes with an angle of -85.93 degrees for a prefault voltage of 1.00 p.u. (13.8 kV line-to-line). For this current, the three-phase fault MVA level is found to be 290 MVA.

ANSI X/R ratio and impedances

The separate X and R reduction resulted in an equivalent reactance $X_{\text{eq}}=0.034$ p.u. and an equivalent resistance of 0.00195 p.u., thus yielding an ANSI X/R ratio of 17.434 ($= 0.034/0.00195$)

First-ring contributions

From bus 4: MILL-2 10 877 amperes at an angle of -85.65 degrees

From MOTOR M-FDR-L 1255 amperes at an angle of -88.34 degrees

Generator contribution classification

Once the contributions have been calculated, the synchronous generator contributions need to be classified as either “local” or “remote.” The following table illustrates the classification process according to the 40% criterion, as outlined in 9.4. Next to the p.u. contribution of every generator is also shown in parentheses the comparison threshold according to which the classification is made. The threshold, for every generator, is 40% of the fault current one would obtain if the generator terminals were boldly faulted.

According to Table 9-10, the fault current featuring no ac decrement is approximately 14.704 p.u. (13.720 p.u. + 0.984 p.u.), amounting to approximately 50.7% of the total fault current. Computer calculations taking into account vectorial arithmetic yielded a total of 50.70%, amounting to a NACD content of 0.507. All motor contributions were, again, considered “local” for this calculation.

Table 9-10— Generator contribution classification for a fault at 8:FDR L

Fault at bus 8:FDR L	Fault current (p.u.) 28.9935
Current from Utility (Remote)	13.720 p.u. (By definition)
Current from GEN1 (Remote)	0.984 p.u. (< 5.5784 p.u)
Current from GEN2 (Local)	9.517 p.u. (> 3.9048 p.u)

Calculation of asymmetrical currents for totally rated breakers

Let us assume for illustration that a three-cycle totally rated breaker is to be applied. Assuming a breaker contact parting time of two cycles, for a fault point X/R ratio of 17.434, one obtains for a three-phase fault a “remote” multiplier of 1.214 and a “local” multiplier of 1.149 from Figure 9-1a and Figure 9-1b respectively. We therefore, obtain the following:

$$I_{\text{asym}} = 12\,130 (1.214) = 14\,726 \text{ A (remote multiplier only)}$$

$$I_{\text{asym}} = 12\,130(0.493)(1.149) + 12\,130(1.214)(0.507) = 14\,337 \text{ A (weighted)}$$

And following the equivalent NACD ratio approach:

$$12\,130 [(1.214-1.149)(0.507)+1.149] = 14\,337 \text{ amperes}$$

Calculation of asymmetrical currents for symmetrically rated breakers

Let us assume for illustration that a three-cycle symmetrically rated breaker is to be applied. Assuming, again, a breaker contact parting time of 2 cycles, for a fault point X/R ratio of 17.434, one obtains for a three-phase fault a “remote” multiplier of 1.012 and a

“local” multiplier of 1.00 from Figure 9-2a and Figure 9-2b respectively. We therefore, obtain:

$$I_{\text{asym}} = 12\,130 (1.012) = 12\,276 \text{ A (remote multiplier only)}$$

$$I_{\text{asym}} = 12.130 (0.493)(1.00) + 12\,130(1.012)(0.507) = 12\,204 \text{ A (weighted)}$$

And following the equivalent NACD ratio approach:

$$12\,130 [(1.012 - 1.00)(0.507) + 1.00] = 12\,204 \text{ amperes}$$

It is seen that using a “remote” multiplier only, the asymmetrical current estimate is higher (more conservative) as compared to the value obtained using a “weighted” approach. This is true for either breaker rating structure. If there is no in-plant generation at all in the industrial system, it is common practice to use the “remote” multiplying factors only. Considering the motor contribution as “remote” would also yield more conservative (higher) asymmetrical fault current estimates.

The classification of the generating station contributions as either “local” or “remote” is a non-trivial calculation, particularly for systems featuring many generators and non-radial topology. These calculations are greatly facilitated by today’s computer programs, which automate these procedures and criteria for any faulted bus, by virtue of well-established analytical techniques (Anderson [B1]). Another advantage of modern-vintage commercial-grade computer software, designed to support ANSI-conformable calculations, is the ability to view the system-wide effects, both voltage-wise on the system buses and current-wise on any branch or source, for any phase or sequence, when simulating a fault at any location. Figure 9-5 illustrates such a typical graphical report, portraying the system state in p.u. something that permits immediate qualitative assessment of the effects of the fault and inspection of the synchronous generator contribution levels. A rather local view is illustrated here, but “zoom” and “pan” facilities should render any part of the single line diagram available for closer inspection. An equally important and “sought-after” attribute of any computer-generated result, besides flexibility and convenience, should be to pro-

vide enough information so that all valid interpretations of the ANSI-related calculations can be applied with ease.

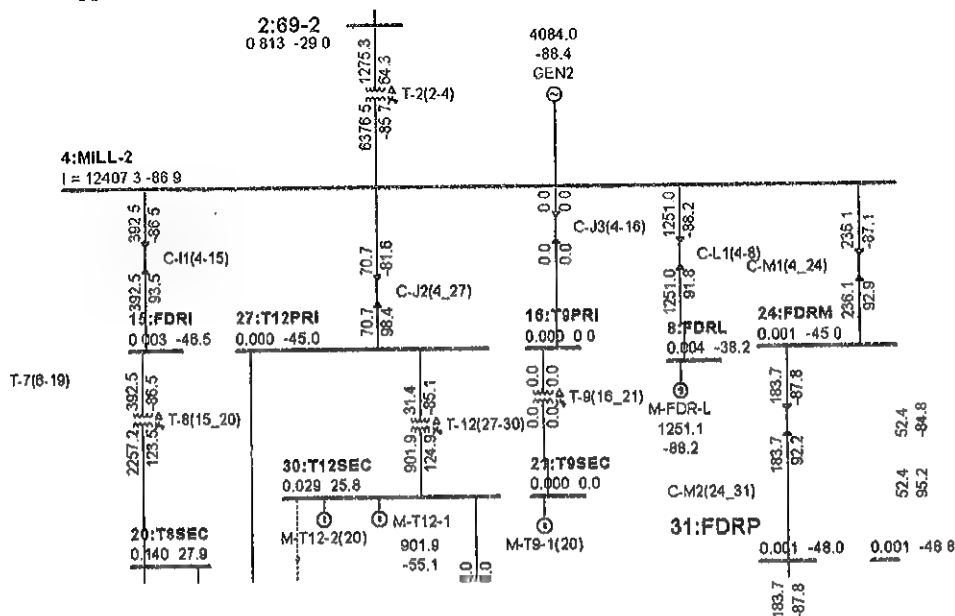


Figure 9-5—Typical computer-generated, system-wide graphical report for Interrupting duty calculations (three-phase fault at bus 4: MILL-2)

9.10 Applying ANSI calculations to non-60 Hz systems

ANSI calculating procedures for interrupting requirements purposes can be applied to system other than 60 Hz. The interrupting equipment manufacturer should, in principle, determine if the equipment can be applied to system frequencies for which it was not originally designed for. For example, most of the breaker and fuse equipment manufactured in the U.S. have a nominal design frequency of 60 Hz, but they are sometimes applied on 50-Hz systems. The three critical factors to keep in mind for equipment ratings and calculating procedures in non-60 Hz systems are asymmetry factor for the first half cycle, contact parting time of high-voltage breakers and the system X/R ratio.

9.10.1 Asymmetry factor equations

The previously defined equations for calculating first cycle peak and 1/2 cycle asymmetrical rms fault remain, in principle, valid for non-60 Hz systems. They both involve either breaker parting time OR system X/R ratio for 60 Hz. The fact remains, however, that both time in cycles of the new frequency as well as the reactance for the new frequency must be consistent.

9.10.2 Breaker contact-parting times and X/R ratio

The contact parting time of a breaker, in seconds, is a function of breaker mechanics and does not change when the breaker is applied on a frequency other than 60 Hz, but the breaker contact-parting time in cycles does change. The techniques for obtaining the “remote” multiplying factors, tabular and analytical, remain valid for other than 60 Hz frequencies provided, again, that the contact-parting time and the X/R ratio are correct and consistent for the new frequency.

The previously defined “local” multiplying factors may still apply provided that the contact parting time in cycles and the X/R ratio remain consistent for the new frequency. Whenever applying dc decrement characteristics from IEEE Std C37.010 it should be remembered that they are still valid but for an X/R ratio of 14 when the system frequency is 50 Hz.

9.11 Normative references

The following referenced documents are indispensable for the application of this document. For dated references, only the edition cited applies. For undated references, the latest edition of the referenced document (including any amendments or corrigenda) applies.

ANSI C37.5, Guide for Calculation of Fault Currents for Application of AC High-Voltage Circuit Breakers Rated on a Total Current Basis.³

IEEE Std C37.010™, IEEE Application Guide for AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis.^{4, 5}

IEEE Std C37.13™, IEEE Standard for Low-voltage AC Power Circuit Breakers Used in Enclosures.

IEEE Std 141™, IEEE Recommended Practice for Electric Power Distribution for Industrial Plants. (*IEEE Red Book*)

IEEE Std 241™, IEEE Recommended Practice for Electric Power Systems for Commercial Buildings. (*IEEE Gray Book*)

IEEE Std 242™, IEEE Recommended Practice for Protection and Coordination of Industrial and Commercial Power systems. (*IEEE Buff Book*)

³ANSI C37.5 has been withdrawn; however, copies can be obtained from the Sales Department, American National Standards Institute, 25 West 43rd Street, 4th Floor, New York, NY 10036, USA (<http://www.ansi.org/>).

⁴IEEE publications are available from the Institute of Electrical and Electronics Engineers, 445 Hoes Lane, P.O. Box 1331, Piscataway, NJ 08855-1331, USA (<http://standards.ieee.org/>).

⁵The IEEE standards or products referred to in this subclause are trademarks of the Institute of Electrical and Electronics Engineers, Inc.

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Chapter 10

Application of short-circuit interrupting equipment

10.1 Introduction

This chapter describes the application of electrical power system interrupting equipment for three-phase and line-to-ground short-circuit currents. The fault currents used are from the one-line diagram used throughout this book and includes generator, induction and synchronous motors contributions. The application of interrupting equipment, in some cases, requires more than comparing an interrupting current given on the nameplate to the calculated duty. The calculation of fault currents in accordance to ANSI-approved standards are covered in Chapter 9. The term *duty* as used in this text is the maximum symmetrical fault current times any multipliers, which makes the resulting current directly comparable with the equipment rating.

10.2 Purpose

The objective of this chapter is to give examples of taking available interrupting equipment data and making comparisons to the calculated short-circuit duty. The capability of the interrupting equipment to adequately interrupt short-circuit currents is a safety as well as a system and equipment protection consideration. The National Electrical Code® (NEC®) (NFPA 70, 2005 Edition)¹ states that "Equipment intended to break current at fault levels shall have an interrupting rating sufficient for the nominal circuit voltage and the current that is available at the line terminals of the equipment." (See NEC, Section 110-9.) "The overcurrent protective devices, the total impedance, the component short-circuit withstand ratings, and other characteristics of the circuit to be protected shall be so selected and coordinated as to permit the circuit protective devices that are used to clear a fault without the occurrence of extensive damage to the electrical components of the circuit." (See NEC, Section 110-10.)

10.3 Application considerations

Once a short-circuit calculation has been made using the best data available, the application or verification of breaker, fuse, switches, and other equipment ratings needs to be made. Subclause 10.7 provides a list on equipment that may have to be checked against the short-circuit fault currents. Depending on the purpose of the fault calculations not all equipment given in 10.7 list will need to be checked. A number of items from the short-circuit calculations have to be considered when comparing the fault currents against the equipment. These are as follows:

- 1) Circuit voltage
- 2) Circuit fault current
- 3) Fault current X/R ratio

¹Information on normative references can be found in 10.12.

- 4) Equipment first cycle withstand capabilities
- 5) Equipment first cycle interrupting current capabilities
- 6) Equipment interrupting time and current capabilities
- 7) Equipment maximum application voltage and maximum interrupting current
- 8) Equipment minimum application voltage and minimum interrupting current
- 9) Equipment interrupting test X/R ratio
- 10) Non-interrupting equipment fault current withstand and thermal capabilities

Several methods are used to modify the fault current or breaker rating when a multiplier is required because of system conditions. A derating factor can be applied to the interrupting device rating or a multiplier can be applied to the current. In this book the latter will be used. In general the multiplier on the current is preferred because the interrupting equipment ratings will remain the same for all buses at the same voltage. Otherwise, the adjusted interrupting equipment current ratings may differ depending on the fault current X/R ratio.

Given in Table 10-1 are the general test X/R ratios of interrupting equipment.

Table 10-1—Minimum test X/R ratios

Type of equipment	First cycle current	First cycle X/R	Interrupting time or short time X/R
Low-voltage power circuit breaker (iron frame breaker)	Peak	6.59	6.59
Low-voltage molded and insulated case breakers with interrupting ratings > 20 kA	Peak	4.9	4.9
Low-voltage molded and insulated case breakers with interrupting ratings 10-20 kA	Peak	3.18	3.18
Low-voltage molded and insulated case breakers with interrupting ratings < 10 kA	Peak	1.73	1.73
Fused low-voltage power circuit breakers	Peak	4.9	4.9
Low-voltage busway	Peak	4.9	4.9
High-voltage power circuit breaker	rms	25	15
Power fuse	rms	15	—
Distribution fuse	rms	10	—
Distribution air cutout fuse	rms	5–15 depends on kV rating	—
Distribution oil cutout fuse	rms	9–12 depends on kV rating	—

Table 10-1—Minimum test X/R ratios (continued)

Type of equipment	First cycle current	First cycle X/R	Interrupting time or short time X/R
Switches (withstand rating)	rms	25	—
High-voltage bus duct		25	—

10.4 Equipment data

Equipment rating data for a particular type of equipment can vary over several years of manufacture depending upon improvements in the equipment, special limitation of the equipment, or changes in the rating structure. The recommended ratings and required data to be placed on equipment nameplates is given in the appropriate ANSI, IEEE, and NEMA standards for the equipment. Short-circuit test requirements given by NEMA, Underwriters Laboratories, ANSI, or IEEE are generally the same for the type of equipment involved. Not all manufacturers follow the standards' recommended rating structure. Some interrupting equipment may be sized to fit an area not covered by the standards or the equipment may have a higher or lower interrupting capability than suggested by the standard recommended ratings system.

Several examples of equipment rating changes are given below. The broad range of GE type AM-13.8-500 medium-voltage class of breakers used in metal-clad switchgear covers many years. During the years of manufacture, the ANSI rating structure was revised and the breaker design was changed to accommodate the change. In the mid-60s the breaker design and nameplate reflected the ANSI change of total current method of testing to the symmetrical current method of testing. Unless additional data is furnished, (Series No., year of manufacture, complete nameplate data) there is no way to determine the actual rating of the breaker. A second example is the BBC type xx-HK-xxx medium-voltage class of breakers rated on a symmetrical current basis have a 5 cycle interrupting time. However, the breaker nameplate and literature gives a 1.2 asymmetry factor. This information indicates that the breaker has a 2-cycle contact parting time rather than the three cycles contact parting normally associated with 5-cycle interrupting time breakers. A third case is that S&C power fuses literature provides varying symmetrical interrupting ratings depending upon the system fault X/R ratio. Normally most manufacturers of power fuses provide only one interrupting rating at an X/R ratio of 15.

Based on the previous discussion, rating variations from different vendors are possible and care should be exercised in using general equipment data. The preference order of obtaining equipment data is as follows as follows:

- 1) Equipment nameplate
- 2) Manufacturer's literature
- 3) ANSI, IEEE, or NEMA standards

10.5 Fully-rated systems

In a fully-rated system, all interrupting equipment is applied to interrupt the total fault current at the point of the fault. All high-voltage breakers require a fully-rated system. All low-voltage power circuit breakers (iron frame) require a fully-rated system. All low-voltage systems greater than 480 volts require a fully-rated system.

The use of first half cycle current-limiting interrupting devices on a high-voltage system to reduce the amount of fault current the breakers have to interrupt is not covered by the standards. The manufacturer of a breaker used in such a manner should be consulted to determine its acceptability and change in warranty, if any.

Section 110-9 of the NEC requires that fault interrupting devices have an interrupting rating sufficient to withstand the current to be interrupted. This is commonly known as a fully-rated system. However, low-voltage series rated equipment is allowed.

10.6 Low-voltage series rated equipment

Series rating on equipment allows the application of two series interrupting devices for a condition where the available fault current is greater than the interrupting rating of the downstream equipment. Both devices share in the interruption of the fault and selectivity is sacrificed at high fault levels. Selectivity should be maintained for tripping currents caused by overloads.

The NEC states "If a circuit breaker is used on a circuit having an available fault current higher than its marked interrupting rating by being connected on the load side of an acceptable overcurrent protective device having the higher rating..., this series combination rating shall be marked on the end use equipment." (See NEC, Section 249-6.) In this case, the short-circuit rating assigned to the combination of the series devices can be higher than the lowest downstream rated device of the combination.

In a series combination of fuses or breakers, series rated equipment must meet some strict rules in order to be applied.

- 1) Series rated combinations should be selected by a registered professional engineer whose primary occupation is the design and maintenance of electrical installations. The design documents should be stamped with the seal of the professional engineer.
- 2) A series combination is recognized for series application by a third-party organization such as UL. UL 489-2002 outlines the test connections and procedures for proof of series combination ratings. Analytical methods such as the "up-over-and-down" method for applying fuses may not be used for circuit breakers that exhibit contact parting in the first half-cycle.
- 3) The tested combination does not allow for faults closer than four feet from the load side breaker.

- 4) The current in the two interrupting devices must be the same current. Motor fault current contribution that would allow the downstream breaker to have a higher current as compared to the upstream breaker/fuse is not allowed.
- 5) Series ratings apply to systems at 600 V and below.
- 6) The series rating test has been made at only one power factor, whereas the actual fault power factor could vary widely.
- 7) Since the load breaker is subject to higher than rated fault currents, it should be thoroughly checked and tested after each fault operation.
- 8) Series ratings apply for selected low-voltage equipment (Molded-case circuit breakers and current limiting fuses).
- 9) Upstream devices must have instantaneous trips or clearing times.
- 10) There is no limitation on physical distance between interrupting devices.

A listing of the tested combinations can be obtained from the UL Recognized Component Directory (UL-RCD). Usage of series rated protective devices does not lead to a coordinated selective system but to a protective system, wherein the system reliability is sacrificed because of the loss of selectivity of protective equipment.

10.7 Low-voltage circuit breaker short-circuit capabilities less than rating

The ANSI test standard for low-voltage power breakers describes a short-circuit test for breakers where full line-to-line voltage is applied across an interrupting pole of a breaker. For this condition, the breaker must be capable of interrupting at least 87% of its three-phase interrupting rating. For a single phase system where two poles of a three-phase breaker are used to interrupt the short circuit, the one pole, full voltage, 87% capability does not apply because each pole "sees" 50% of the line-to-line voltage, which is less than the normal line-to-neutral voltage of a three-phase system. Using a single pole of a three-phase breaker to interrupt a single phase line-to-line short circuit requires that the breaker single pole voltage capability be greater than the normal line-to-neutral voltage of the system or a reduced interrupting rating will apply.

The most likely cause of an interruption of a line-to-line short circuit by one pole of a circuit breaker is a double line-to-ground short circuit in a three-phase system that is not solidly wye grounded, such as an ungrounded system, high resistance grounded system, or corner of the delta grounded system. Full line-to-line recovery voltage can occur across a single interrupting pole when one phase is grounded on the source side of a circuit breaker and another phase is grounded simultaneously on the load side. For a corner of the delta grounded system, this might be a common occurrence. The situation is less likely to occur in high resistance grounded or ungrounded systems where operating procedures require the first ground to be removed as soon as practical.

The single-pole interruption problem should not be a concern with low-voltage power breaker because they are tested to meet the criteria in IEEE Std C37.010™-1999. The maximum line-to-line first cycle short-circuit duty is 87% of the three-phase duty in a three-phase system. If the power circuit breaker is correctly applied for a three-phase

short-circuit duty, then it is correctly applied for the line-to-line duty independent of the system grounding. The limiting application may be for a line-to-ground fault on a solidly grounded system where the line-to-ground fault current may be greater than the three-phase current, e.g., on the secondary of a transformer.

However, the single-pole interrupting ratings assigned to low-voltage molded case or insulated case circuit breakers may be based on UL or NEMA standard values, which may be lower than ANSI requirements. If this restricts an application, the manufacturer should be consulted because single pole tests using voltages and currents higher than literature values may have been performed, relieving the restriction.

10.8 Equipment checklist for short-circuit currents evaluation

The following is a listing of items that may need to be compared against the calculated fault levels. Depending on the purpose of the short-circuit study not all items will need to be checked. The list does show that there are more devices affected by short-circuit than just interrupting devices such as fuses and breakers.

- 1) *Fuses*—Fuse voltage rating and first cycle interrupting current.
- 2) *High-voltage breakers*—Voltage rating, first cycle current, interrupting current. A system rated 4.8 kV often requires equipment rated at 7.2 kV because the upper limit of some 4.16 kV class of equipment is 4.76 kV.
- 3) *Low-voltage breakers*—Voltage rating, first cycle current (Interrupting), short time current rating if no instantaneous is supplied, and single pole interrupting rating.
- 4) *Switches*—First cycle current for withstand capabilities.
- 5) *Switchgear, motor control centers*—First cycle current for bus bracing and molded case interrupters.
- 6) *Reclosers*—Voltage rating, first cycle current, interrupting current.
- 7) *Cable heating limits*—First cycle, interrupting, and time delay relay currents. This check is more important on systems with time delay tripping and where selective relay operating times are required. The heat generated in the cable during the fault could over heat the insulation and deteriorate or melt it. Extremely small cable while within its load rating could act as a fuse under high fault currents.
- 8) *Line heating limits*—First cycle, interrupting, and time delay relay currents. This check is more important on systems with time delay tripping. The heat generated in the line during the fault could over heat the line causing more sag and possibly a second fault, injury, or line melt down.
- 9) *Current limiting reactors*—First cycle to check the through current. Per ANSI 57.16, the rms short-circuit should be less than 33.33 times the rated rms current.
- 10) *Busways and bus ducts*—First cycle current to check the bus bracing.
- 11) *Transformers*—First cycle and time-delay currents for mechanical and thermal withstand limits. The transformer overcurrent relays should be set to protect these limits per ANSI C57.109.

- 12) *Line carrier frequency wire traps*—First cycle and time delay currents for mechanical and thermal withstand limits. Wire traps can be the limiting item on a transmission line.
- 13) *Current transformers*—First cycle and time delay currents for the mechanical and thermal withstand limits. High primary currents can cause current transformer saturation that may affect relay operation.
- 14) *Generators*—First cycle line-to-ground fault currents on non-impedance grounded generators can have line-to-ground fault currents that are greater than the three-phase fault current. The winding bracing of the generator is based on three-phase fault currents.
- 15) *Grounding resistors and reactors*—Time delay line-to-ground fault currents if not properly relayed can exceed the short time ratings of generator and transformer grounding devices.
- 16) *Series capacitors*—First cycle fault currents will result in high voltages across the capacitors that may exceed both the transient current and voltage capability of the capacitors and its protective surge equipment.

10.9 Equipment phase duty calculations

The following subclause calculates the first cycle and interrupting time fault current duties on the above listed equipment. The symmetrical fault currents used to calculate the duties was taken from the computer printout in Chapter 9. Chapter 3 through Chapter 9 provide the details of the network reduction needed to determine the symmetrical fault currents.

10.9.1 13.8 kV Breakers

The high-voltage breakers on buses 03:MILL-1 and 04:MILL-2 must be evaluated on both a first cycle and interrupting time bases. The first cycle duty is compared against the “close and latch” rating of the symmetrical rated breakers and the “momentary” rating of the total current rated breakers. The total symmetrical 03:MILL-1 bus fault current is 13.952 kA and the maximum current that a breaker on that bus can see is that for breaker G, the smallest bus current contribution. The breaker current is $13.837 - 0.179 = 13.658$ kA, symmetrical. Since the breaker duty is 98.7% of the bus duty, the more conservative bus fault currents will be used as breaker duties.

Some of the more recent breakers also have a peak current given on the nameplate for the close and latch rating. This peak rating is 2.7 times the breaker maximum interrupting current.

The first cycle test X/R for these breakers is 25 and Table 10-2 provides the comparisons of duty to ratings. The equation for the first cycle rms asymmetrical current is shown in Equation (10-1):

$$\tau = 0.49 - 0.1e^{-\frac{X}{3R}} \quad (10.1)$$

$$I_{rms} = I_{sym} \sqrt{1 + 2e^{-\frac{2\pi\tau R}{X}}} \quad (10.2)$$

Table 10-2—First cycle evaluation

Bus	Breaker	Fault <i>X/R</i>	Sym. kA	Multi- plier	Duty asym. kA	Breaker rating kA	Bus kA bracing
03:MILL-1	AM-13.8- 500-3	17.32	13.837	1.550	21.45	40	40
03:MILL-1	VB-13.8- 500-1	17.32	13.837	1.550	21.45	38	40
04:MILL-2	15-HK-500	22.29	13.888	1.587	22.04	40	40

The interrupting breaker duty requires additional information concerning the speed of the breaker, the test procedure used for the breaker at the time of manufacture, total symmetrical fault current, fault current *X/R* ratio, and the amount of current from nearby generators. Chapter 9 went into detail on calculating the amount of current from each generator, therefore to avoid repeating this detail, the currents will be taken directly from the computer printout. For each fault, the amount of the generator current considered "local" from each will have to be determined. When the generator fault current is greater than 40% of a generator terminal fault current, then the current is considered "local." The listing below summarizes these findings at the bus fault voltage.

Table 10-3—Identification of Major Source Currents at 13.8 kV

Bus Fault	Generator	Fault	Term. fault	Ter- minal	40% of current	Fault current	Fault
03:MILL-1	100:UTIL-69	5.904	^a	5.904	Remote		
03:MILL-1	50:GEN-1	5.835	2.334	5.825	Local		
03:MILL-1	04:MILL-2	4.084	1.634	0.318	Remote		
04:MILL-1	100:UTIL-69	5.888	^a	5.888	Remote		
04:MILL-2	50:GEN-1	5.835	2.334	0.422	Remote		

^aDoes not apply.

The next item to be determined is the weighing factor of the “remote” and “local” currents. IEEE Std C37.010 allows several options in regard to the treatment of motors. They can be considered all “remote,” or all “local.” The local and remote data is used to determine the interrupting current multiplier. The following listing calculates the ratio based on several options. The ratio is commonly called the NACD ratio (No AC Decay Current).

Option 1 - Most conservative

Consider all source current remote; this will give the highest multiplier and will assume no ac decay.

The NACD ratio = 1.0.

Option 2 - Less conservative

Consider the motor contribution to be remote. The equation below does this by knowing the total bus fault current and the amount of current identified as local.

$$\text{NACD} = (\text{Total} - \text{local})/\text{Total}$$

Option 3 - Least conservative

Consider the motor contribution to be local. The equation below does this by knowing the total bus fault current and the amount of current identified as remote from the major sources.

Bus 03:MILL-1 has breakers that were manufactured under two different test procedures. The older breakers were tested under the “Total” current basis of rating and the newer breakers were tested under the “Symmetrical” current basis of rating. Bus 04:MILL-2 has breakers that were tested under the “Symmetrical” current basis of rating. From the curves of Figure 9-1 and Figure 9-2a, the duty multipliers can be determined by the following steps.

**Table 10-4—Identification of local and remote currents at 13.8 kV—
NACD = remote/total**

	Total	Local	Remote	NACD ratio		
Bus fault	Fault current	Current	Current	Option #1	Option #2	Option #3
03:MILL-1	12.902	5.825	6.222	1.000	0.5485	0.4823
04:MILL-2	12.407	4.084	6.310	1.000	0.6708	0.5086
NOTE—Motor contribution not included.						

Step 1—Determine the Total current multipliers from the REMOTE curves of Figure 9-1 based on the fault point X/R ratio. These multipliers can be taken from the curves or calculated from the following equation:

$$(1 + 2 \times e^{-4\pi C/(X/R)})^{1/2}$$

Note that the breakers on bus 04:MILL-2 have an asymmetrical rating factor or 'S' factor of 1.2. This means that the 5-cycle interrupting time breaker has a contact parting time of two cycles rather than three cycles normally associated with 5-cycle breakers. For the breakers rated on a symmetrical current basis divide the multiplier by the breaker "S" factor (1.1 for bus 03:MILL-1 and 1.2 for bus 04:MILL-2). For the symmetrically rated breakers this multiplier could have been read directly from Figure 9-2a.

Step 2—Determine the Local current multipliers from the LOCAL curves of Figure 9-1a and Figure 9-2a based on the fault point X/R ratio. These points can be taken from the curves or calculated from the empirical equations given in Chapter 9.

Step 3—The final step is to adjust the multipliers based on the NACD ratio. Ratios of 1.0 or 0.0 can use the multipliers directly. The duty multiplier is:

$$[(\text{Remote Multiplier} - \text{Local Multiplier}) \times \text{NACD Ratio} + \text{Local Multiplier}]$$

**Table 10-5—Local and remote multipliers for buses
03:MILL-1 and 04:MILL-2**

Bus	Breaker	Test standard	Contact part time	"S" factor	Fault X/R	Remote mult.	Local mult.	Figure
03:MILL-1	AM-13.8-500-3	Total	4 Cy	1.0	17.92	1.059	0.972	9-1a,1b
03:MILL-1	VB-13.8-500-1	Sym	3 Cy	1.1	17.92	1.115 ^a	1.044 ^a	9-1a,1b
04:MILL-2	15-HK-500	Sym	2 Cy	1.2	22.73	1.289 ^a	1.217 ^a	9-1a,1b
03:MILL-1	AM-13.8-500-3	Total	4 Cy	1.0	17.92	1.059	0.972	9-1a,1b

^aDividing these multipliers by "S" will obtain Figure 9-2a and Figure 9-2b.

Table 10-6—Duty current multipliers for buses 03:MILL-1 and 04:MILL-2

	Test	Fault	Final multiplier			Duty current			Rating
Bus	Standard	Sym kA	Option 1	Option 2	Option 3	Option 1	Option 2	Option 3	kA
03:MILL-1	Total	12.902	1.059	1.020	1.014	13.66	13.16	13.08	20.9
03:MILL-1	Sym	12.902	1.014	1.000 ^a	1.000 ^a	13.08	12.90	12.90	19.6
04:MILL-2	Sym	12.407	1.074	1.054	1.044	13.33	13.08	12.96	21.0

^aIf the final multiplier is less than 1.0 use 1.0.

The breaker ratings at 13.8 kV vary a little depending on the nameplate data even though they are all the same class of breaker. The AM-13.8-500-3 is the total current rated breaker and has a constant MVA rating between the rated maximum voltage and the voltage that results in the maximum interrupting kA (11.5 kV). Applying the breaker at voltages lower than 11.5 kV, the breaker is a constant current interrupting device. The breaker interrupting rating at 13.8 kV is shown in Equation (10.3):

$$500 \text{ MVA} / 13.8 \text{ kV} / \sqrt{3} = 20.9 \text{ kA} \quad (10.3)$$

The AM-13.8-500-4 and 15-HK-500 are symmetrical current rated breakers and the interrupting current is calculated by:

$$\frac{\text{Rated max voltage}}{\text{Bus voltage}} \times \text{Rated short circuit current}$$

The interrupting capability cannot exceed:

$$\text{Rated short-circuit current} \times \text{Voltage range factor}$$

or

$$\text{First cycle (close and latch)/voltage range factor.}$$

The values should be the same when rounded off.

Breaker VB-13.8-500-1 interrupting rating at 13.8 kV is:

$$15.0 \times 18 / 13.8 = 19.6 \text{ kA}$$

The current does not exceed $18 \times 1.3 = 23.4$ kA breaker maximum interrupting rating.

Breaker 15-HK-500 interrupting rating is:

$$15.0 \times 19.3 / 13.8 = 21.0 \text{ kA}$$

The current does not exceed $19.3 \times 1.3 = 25.0$ kA breaker maximum interrupting rating.

In the above example with the 13.8 kV tie breaker open, the breaker duty current is less than its rating and the breakers are correctly applied. The fault current when the tie breaker is closed has not been examined for proper equipment application in this book. However, by following the above procedure the reader can verify the breaker application when the 13.8 kV tie breaker is closed. From inspection of the one-line diagram and the above results, the bus duty when the 13.8 kV tie is closed will almost double. For this system, it appears that the tie 13.8 kV breaker cannot be closed unless a transformer or generator is out of service.

10.9.2 13.8 kV bus disconnect switch

Bus disconnect switch (Bus 09:FDR E) based on standards has a first cycle asymmetry factor of 1.6 that is equivalent to a fault X/R ratio of 25. The calculated symmetrical fault current, from Chapter 9, is 13.268 kA @ 13.8KV with a fault point X/R ratio of 9.82. This results in an asymmetry factor of 1.44 or 19.00 kA asymmetrical duty. Use Equation (10.2) to determine the asymmetry factor. The disconnect switch has an asymmetrical withstand rating of 34 kA and an asymmetrical interrupting rating of 19.2 kA. The asymmetrical interrupting rating would be used if the switch had opening times

based on instantaneous relaying. This switch is correctly applied for the first cycle and interrupting time fault duties calculated.

10.9.3 13.8 kV transformer primary fuse

T17 transformer (Bus 05: FDR F) has a primary fuse and based on standards has an asymmetry factor of 1.55, which is equivalent to a fault X/R ratio of 15. The fuse nameplate interrupting rating is 20 kA asymmetrical. However, the manufacturer's literature states that these fuses are tested at X/R of 20 or an asymmetry factor of 1.57 (rounded to 1.6 in the literature). Also given in the literature are interrupting ratings at several X/R ratios less than 20. For this fuse, these ratings are:

$X/R = 20$ symmetrical interrupting 12.5 kA

$X/R = 15$ symmetrical interrupting 12.5 kA

$X/R = 10$ symmetrical interrupting 13.7 kA

$X/R = 5$ symmetrical interrupting 16.0 kA

The fault point X/R is 12.58 and therefore the fault duty of 13.548 kA symmetrical is greater than the fuse rating of 12.5 kA symmetrical. This fuse is not correctly applied for the fault duties calculated and should be replaced with a fuse with a higher interrupting capability such as an S&C SM-5 fuse, which has a rating of 25 kA symmetrical at an X/R of 15.

10.9.4 480 V load center

The secondary of load center 28:T10 SEC has three different types of breakers; the main without an instantaneous trip and high continuous current rating, the motor control center breaker without an instantaneous trip and lower continuous current rating, and the lighting panel feeder with a fused breaker with an instantaneous trip and the lowest continuous current rating. Calculated duties for these devices are listed in Table 10-7.

These breaker are power circuit breaker types and have a test X/R ratio of 6.59 for the non-fused breaker and 4.9 for the fused breaker. Since the first cycle fault point X/R of 6.55 is greater than 4.9 required for the fused breaker a current modification may be required. No modification of the current is needed for the unfused breakers because the breaker test X/R ratio is greater than the fault point X/R ratio. The first cycle breaker duty is $34.56 \times 1.0 = 34.56$ kA. For the fused breaker, the multiplier is:

First cycle multiplier = I_{peak} at fault point $X/R / I_{\text{peak}}$ at test $X/R = 1.061$

The peak current multiplier is from the equations that follow.

$$\tau = 0.49 - 0.1e^{-(X/R)/3}$$

$$I_{\text{peak}} = \sqrt{2} \times (1 + e^{(-2\pi\tau/(X/R))})$$

Table 10-7—Duty current for low-voltage breakers on bus 28:T10 SEC

		Test	Fault	First cycle	Short time	Breaker kA rating	
Breaker	Type	X/R	X/R	kA duty ^a	kA duty	1st cy	Short time
Main	PCB	6.59	6.55	28.68	29.73 ^b	85	65 ^b
MCC feeder	PCB	6.59	6.55	34.56	29.73 ^b	65	50 ^b
Lighting	Fused PCB	4.9	6.55	36.67	29.73	200	-

^aMain breaker given as breaker duty, feeders given as bus duty.

^bBreakers without instantaneous trips, short-time rating apply.

10.9.5 480 V motor control center

The motor control center (Bus 33:T10MCC) has molded case breakers with a rating greater than 20 kA, therefore the test X/R is 4.9 or greater. The motor control center fault current is 31.87 kA at an X/R of 4.35. No fault current to duty correction is necessary because of the low X/R ratio. The motor control center has 100 ampere HFD breakers rated 65 kA interrupting and 60 ampere LC breaker rated 30 kA interrupting. The HFD breaker is correctly applied and LC breaker is placed in a situation where it is required to interrupt more current than its rating and has to be replaced with a breaker of higher interrupting capability. The bus bracing is 42 kA symmetrical and greater than the bus duty of 31.87 kA.

10.9.6 480 V lighting panelboard

The lighting panelboard (Bus 41:LGTS) has molded case breakers with a rating greater than 20 kA, therefore the test X/R is 4.9 or greater. The panelboard fault X/R is 4.2 and no fault current correction is necessary for the breaker duty. Note that the fault current is 32.05 kA on breakers rated 30 kA; the series rating of the class L fuse located on the 480 V load center feeder breaker in combination with the LC breaker has a combined rating of 100 kA making this a correct application.

10.9.7 Cables

A check on the cables shows that the smallest cable is 250 kcmil and the highest fault that can occur on the cable is from bus 04: MILL-2. From the Chapter 9 study results, the rms current is initially 22.03 kA (first cycle rms asymmetrical) and decays to 12.407 kA (interrupting time symmetrical). If the cable insulation is polyethylene rated 75 °C, then the cable can withstand 20 kA for 0.45 seconds and 15 kA for 0.7 seconds.

The times indicate that the cable will not be thermally damaged for faults that are cleared in instantaneous or with one time step (0.35–0.40 seconds) of relaying.

Some of the pieces of equipment used in the above example are applied close to their ratings. Closing the 13.8 kV tie breaker would in some cases result in the fault duties being greater than the equipment withstand or interrupting ratings.

10.10 Equipment ground fault duty calculations

The 13.8 kV system given has a low ground fault current because of the 400 A, 20 ohm resistors on the generator and transformer neutrals. The ground fault current is approximately 800 amperes and significantly lower than the breaker interrupting rating so the ground fault duty is not a concern.

For purposes of illustration, let's assume that bus 03:MILL-1 has a 13.8 kV ground fault current of 23 kA at an X/R of 10 and all from remote sources. The ANSI standard allows the breaker ground current interrupting rating to be 15% greater than the phase current provided the maximum current rating of the breaker is not exceeded. Table 10-8 provides the breaker rating and duty comparison.

Table 10-8—Calculated single-line-to-ground fault duties compared with breaker ratings

Breaker	Sym kA	Fault	Duty mult.	Duty kA	Phase kA rating	Gnd. kA rating	Breaker
AM-13.8-500-3		23.0	1.00	23.0	20.9	24.0	AM-13.8-500-3
VB-13.8-500-1	23.0		1.00	23.0	19.6	22.5	VB-13.8-500-1

The AM-13.8-500 breaker is correctly applied while the VB-13.8-500 is subject to ground fault current over its rating.

10.11 Capacitor switching

Breakers used for capacitor switching must be able to withstand the short-circuit duties between the breaker and capacitor and the transient currents that come from the capacitor when the fault is on the source side of the breaker. If the size of the load capacitor bank is equal to or less than the maximum capacitor size allowed by the manufacturer on its breaker, then the breaker can handle the capacitor current to a fault on the source side of the breaker. The inrush current when energizing a capacitor is approximately the same as the current when de-energizing a capacitor bank into a fault. In one case, the source voltage is known and the capacitor voltage is a zero; in the second case, the internal

voltage of the capacitor is known and the bus voltage is zero. If 1.0 per-unit voltage is used for either source voltages then the currents are the same. ANSI C37.012-1979 covers capacitor switching in some detail. Chapter 7 provides summary of capacitor current considerations.

10.12 Normative references

The following referenced documents are indispensable for the application of this document. For dated references, only the edition cited applies. For undated references, the latest edition of the referenced document (including any amendments or corrigenda) applies.

ANSI C37.06-1997, American National Standard for Switchgear—AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis—Preferred Ratings and Related Required Capabilities.²

ANSI C37.32-1996, American National Standard for Switchgear-High-Voltage Air Switches, Bus Supports, and Switch Accessories—Schedules of Preferred Ratings, Manufacturing Specifications, and Application Guide.

ANSI C37.42-1996, American National Standard Specification for High-Voltage Expulsion Type Distribution Class Fuses, Cutouts, Fuse Disconnecting Switches and Fuse Links.

ANSI C37.43-1969, Test Code for High-Voltage Air Switches.³

ANSI C37.44-1981 (Reaff 1992), American National Standard Specifications for Distribution Oil Cutouts and Fuse Links.

ANSI C37.45-1981 (Reaff 1992), American National Standard Specifications for Distribution Enclosed Single-Pole Air Switches.

ANSI C37.46-2000, American National Standard for High-Voltage Expulsion and Current Limiting Type Power Class Fuses and Fuse Disconnecting Switches.

ANSI C37.50-1989, American National Standard for Low-Voltage AC Power Circuit Breakers Used on Enclosures—Test Procedures.

ANSI C97.1-1972 (R1978), Low-Voltage Cartridge Fuses 600 Volts or Less.⁴

²ANSI publications are available from the Sales Department, American National Standards Institute, 25 West 43rd Street, 4th Floor, New York, NY 10036, USA (<http://www.ansi.org/>).

³ANSI C37.43-1969 has been withdrawn; however, copies can be obtained from the Sales Department, American National Standards Institute, 25 West 43rd Street, 4th Floor, New York, NY 10036, USA (<http://www.ansi.org/>).

⁴ANSI C97.1-1972 has been withdrawn; however, copies can be obtained from the Sales Department, American National Standards Institute, 25 West 43rd Street, 4th Floor, New York, NY 10036, USA (<http://www.ansi.org/>).

IEEE Std C37.04™-1999, IEEE Standard Rating Structure for AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis.^{5, 6}

IEEE Std C37.09™-1999, IEEE Standard Test Procedures for AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis.

IEEE Std C37.010™-1999 (Reaff 2005), IEEE Application Guide for AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis.

IEEE Std C37.012™-1979, IEEE Application Guide for Capacitors Current Switching for AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Bases.

IEEE Std C37.13™-1990, IEEE Standard for Low-Voltage AC Power Circuit Breakers used in Enclosures.

IEEE Std C37.30™-1997, American National Standard Definitions and Requirements for High-Voltage Air Switches, Insulators, and Bus Supports.

IEEE Std C37.34™-1994, IEEE Standard Test Code for High-Voltage Switches.

IEEE Std C37.41™-2000, IEEE Standard Design Tests for Distribution Cutouts and Fuse Links, Secondary Fuses, Distribution Enclosed Single-Pole Air Switches, Power Fuses, Fuse Disconnecting Switches, and Accessories.

IEEE Std C57.109™-1993, IEEE Guide for Liquid-Immersed Transformer Through-Fault-Current Duration.

NEMA AB-1-2002, Molded-Case Circuit Breakers and Circuit-Breaker Enclosures.

NEMA FU-1:2002 Standard for Low-voltage Cartridge Fuses.

NFPA 70, 2005 Edition, National Electric Code® (NEC®).⁷

UL-RCD, Recognized Component Directory.⁸

UL 489-2002, Molded-Case Circuit Breakers and Circuit-Breaker Enclosures.

⁵IEEE publications are available from the Institute of Electrical and Electronics Engineers, 445 Hoes Lane, P.O. Box 1331, Piscataway, NJ 08855-1331, USA (<http://standards.ieee.org/>).

⁶The IEEE standards or products referred to in this clause are trademarks of the Institute of Electrical and Electronics Engineers, Inc.

⁷The NEC is published by the National Fire Protection Association, Batterymarch Park, Quincy, MA 02269, USA (<http://www.nfpa.org/>). Copies are also available from the Institute of Electrical and Electronics Engineers, 445 Hoes Lane, P.O. Box 1331, Piscataway, NJ 08855-1331, USA (<http://standards.ieee.org/>).

⁸UL standards are available from Global Engineering Documents, 15 Inverness Way East, Englewood, Colorado 80112, USA (<http://global.ihs.com/>).

Chapter 11

Unbalanced short-circuit currents

11.1 Introduction

This chapter describes the calculations for unbalanced short-circuit currents that are the most common on systems. Other system unbalances, such as an open conductor, are not covered here because they are not a short-circuit condition. References given at the end of this chapter can be consulted if this type of circuit failure is of interest. Unbalanced faults are applicable to utility systems, industrial plants, and commercial buildings. In fact, any three-phase system is subject to unbalanced faults and they occur more often than three-phase faults. Generally, fault currents associated with single line-to-ground faults are lower in magnitude than the currents associated with three-phase faults in the same locations. However, in some instances, single line-to-ground faults can be more severe than three-phase faults. The conditions that bring about this unusual situation typically involve the presence of either multiple grounded-wye autotransformers, or multiple three-winding transformers in which one winding in each transformer is configured in grounded-wye.

This chapter is limited to the consideration of short-circuit currents that occur under the following conditions:

- 1) Short-circuit fault currents that occur in low-voltage ac systems and medium-voltage ac systems operating at a constant frequency and electrically remote from any generators
- 2) For the duration of the short circuit, there is no change in the source driving voltage or voltages that caused the initial short-circuit current to flow. In addition, system impedances remain constant
- 3) The fault impedance is zero and has no current limiting effect
- 4) Load currents are much smaller than the fault current and are neglected

11.2 Purpose

The objective of this chapter is to give a procedure for the calculation of unbalanced short-circuit currents on systems. The network can include equipment with decaying ac fault current sources such as motors and generators. The application and selection of interrupting equipment based on the calculated fault current are covered in Chapter 10. The one-line diagram is the same as used in Chapter 4.

The accurate calculation of unbalanced faults is expedited by the use of symmetrical components, which are covered in Chapter 3. It must be emphasized that symmetrical components determine fault voltages and fault currents only. The actual line currents that flow are a combination of fault, load, and circulating currents. The load or circulating currents are determined in the pre-fault period under pre-fault conditions. The superposition theorem permits the addition of the fault currents in each branch of the

network to the pre-fault current. In general, load currents are relatively small with respect to fault currents and often can be neglected.

11.3 ANSI guidelines

For equipment rating purposes, IEEE Std C37.010™-1999¹ and IEEE Std C37.13™-1990 basically focus on the maximum fault current magnitudes, which are the result of three-phase faults. Limited amount of attention is given to unsymmetrical faults because the interrupting duty is reduced for these types of faults. IEEE Std C37.010 does allow the line-to-ground interrupting current magnitudes to be 15% greater than a three-phase fault provided it does not exceed the maximum current rating of the breaker. As with three-phase faults, a first cycle and interrupting time calculation can be made with the appropriate change in machine impedances. Because the negative and zero sequence impedances do not change significantly, the line-to-ground fault current magnitudes vary less between first cycle and interrupting time currents as compared to the three-phase currents.

The machine positive sequence impedances used in this chapter will be based on interrupting and first cycle impedances as given in IEEE Std C37.010-1999. The representation of synchronous machines by a varying impedance is easily adapted to other analytical techniques, such as IEC 909.

IEEE Std C37.010 includes three other specifications to be used when calculating fault currents. These are as follows:

- 1) The pre-fault bus voltage is 1.0 p.u.
- 2) Separate resistance and reactance networks are to be used to determine the fault point X/R ratio. This X/R ratio is to be used to calculate the total asymmetrical fault current
- 3) Load currents are much smaller than the fault current and neglected

In this chapter, the symmetrical ac component of the short-circuit current varies based on the time after the fault. For the purpose of simplicity and conservatism, ANSI has recommended the following simplified procedure for determining the X/R ratio to be applied for a particular fault. The system impedance diagram is converted to a separate resistance (R) diagram and a separate reactance (X) diagram. The resistance and reactance diagrams are then reduced to a simple resistance (R) and a reactance (X) value at the fault point. These values are then used to determine the system X/R for a particular fault. The X/R value in turn determines the system dc time constant and consequently the rate of decay of the transient dc fault current. By treating the separate R and X as a complex impedance a close conservative approximation (usually within 0.5% for $X/R > 1$) to the true current can be obtained. For simplicity, this method will be used in the sample calculations.

¹Information on normative references can be found in 11.8.

11.4 Procedure

Some of the most important items in an unbalanced fault calculation are the sequence component one-line diagrams and the connection of the sequence networks for different types of faults. The negative sequence diagram is basically the positive sequence diagram with no voltage source(s) and with some impedances of the synchronous machine being changed. Often the assumption that the negative sequence impedances are the same as the positive sequence impedances is used. This is a fairly good assumption except for rotating machines where the negative sequence impedance is constant and the positive sequence impedance changes with the time period being studied (to account for ac decay). For first cycle calculations, the negative sequence impedance and positive sequence impedance are similar in magnitude.

The zero sequence diagram is more complex and the impedances may not be as readily available. The type of grounding on generators and transformers must be included in the zero sequence diagrams. Transformer winding configurations, manner of grounding, and zero sequence impedances are important and have to be correctly represented or the results will be meaningless.

The steps in performing an unbalanced fault calculation are as follows:

- 1) Obtain sequence impedances on the apparatus such as generators, motors, and transformers and circuits such as cables, duct, and lines
- 2) Convert impedances to a per-unit value on a common VA base, such as 100 MVA or 10 MVA, if the per-unit system is used for calculation
- 3) Construct each of the three sequence impedance networks for the electrical system that is under study
- 4) Reduce the sequence networks to simplify calculations (as appropriate)
- 5) Connect the sequence network for the type of fault desired
- 6) Calculate the sequence currents
- 7) Calculate the fault and line currents

Figure 11-1 and Table 11-1 provide the positive, negative, and zero sequence diagrams for the various types of power system equipment. Figure 11-2a, Figure 11-2b, and Figure 11-2c provide the sequence diagrams for transformers. These diagrams are important because they define the flow path of ground current in a transformer and the possible isolation of ground fault currents from one voltage level to the next. Also note that the construction of the transformer (core or shell design) may affect the sequence network or zero sequence impedances.

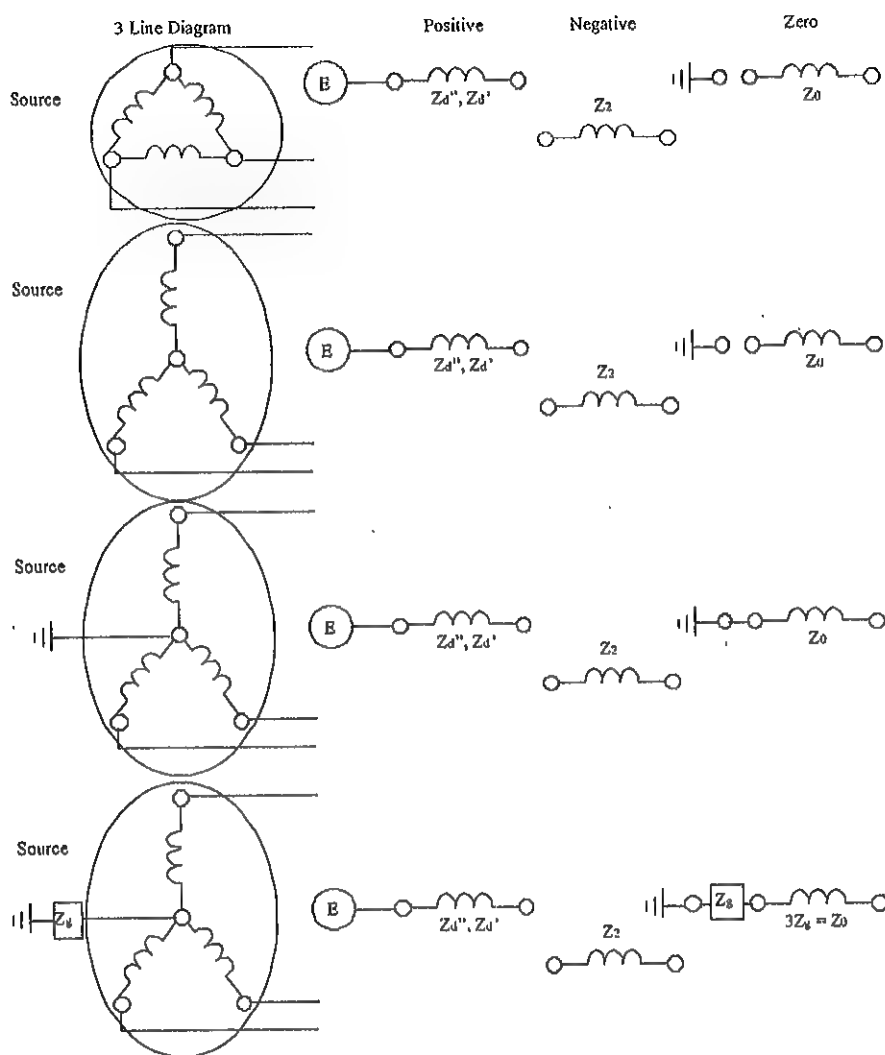


Figure 11-1—Sequence networks for power system equipment

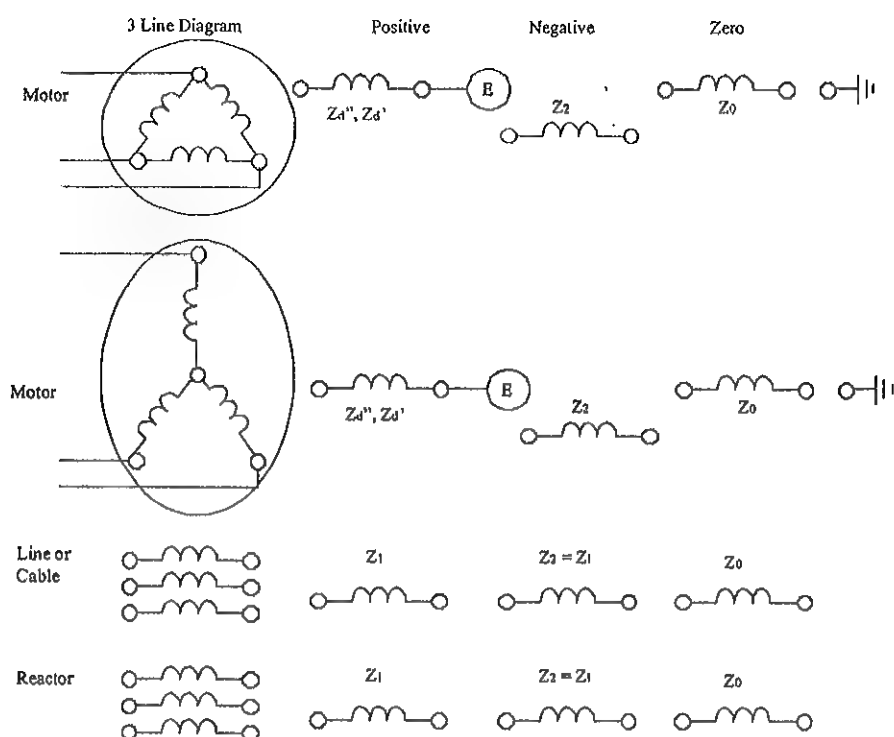


Figure 11-1—Sequence networks for power system equipment (continued)

Table 11-1—Equipment sequence impedances

Circuit or apparatus	Positive sequence	Negative sequence	Zero sequence	Remarks
Utility ^a	R_1, X_1	R_2, X_2	R_0, X_0	Often $X_2 = X_1$
Syn. generator	R_1, X_d'', X_d'	R_2, X_2	R_0, X_0	Usually grounded through a resistor or transformer
Syn. condenser	R_1, X_d'', X_d'	R_2, X_2	R_0, X_0	Neutral may or may not be grounded
Syn. motor	R_1, X_d'', X_d'	R_2, X_2	R_0, X_0	Neutral seldom grounded
Induction motor	R_1, X''	R_2, X_2	R_0, X_0	Neutral not grounded
Transformer	R_1, X_1	R_1, X_1	R_0, X_0	Wye winding usually solidly or impedance grounded

Table 11-1—Equipment sequence impedances (*continued*)

Circuit or apparatus	Positive sequence	Negative sequence	Zero sequence	Remarks
Auto-transformer	R_1, X_1	R_1, X_1	R_0, X_0	Usually solidly grounded
Reactor	R_1, X_1	R_1, X_1	R_1, X_1	
Neutral resistor	—	—	$3R_1$	
Neutral reactor	—	—	$3X_1$	
Cable	R_1, X_1	R_1, X_1	R_0, X_0	
Overhead lines	R_1, X_1	R_1, X_1	R_0, X_0	
Busway	R_1, X_1	R_1, X_1	R_0, X_0	

^aNote that the utility system representation will typically be a Thevenin equivalent obtained by a reduction of the utility system at the fault point. The equivalent impedance is often a worst-case value (to give the highest fault current) and will not be modified for ac decay.

Figure 11-2a shows a diagram that will be used to explain the sequence networks for transformers. The information will be presented in tabular form in Table 11-2 for given connections to obtain the sequence networks. The table will show how major nodes will be connected.

As an example, Figure 11-2b shows the positive and zero sequence connections for a three-phase transformer with the HV (h) winding connected in delta and the LV (x) winding connected in grounded wye (through impedance Z_g).

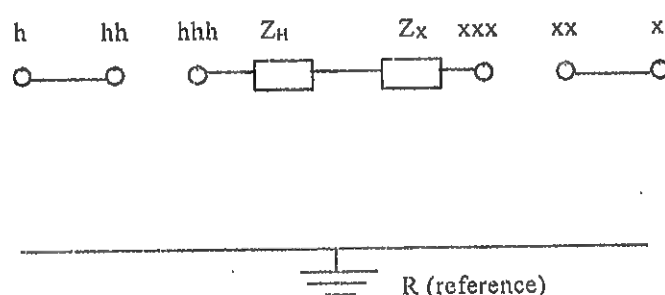


Figure 11-2a—Sequence networks for transformers

Table 11-2—Connection specifications for Figure 11-2a

Transformer connections		Positive or negative sequence		Zero sequence	
Winding H	Winding L	Winding H	Winding L	Winding H	Winding L
Delta	Wye	Short hh to hhh	Short xx to xxx	Short hhh to R	Open xxx to xx
Delta	Solidly grounded wye	Short hh to hhh	Short xx to xxx	Short hhh to R	Short xx to xxx
Delta	Wye (grounded through Z_{gnd})	Short hh to hhh	Short xx to xxx	Short hhh to R	Connect xx to xxx through $3Z_{gnd}$
Delta	Delta	Short hh to hhh	Short xx to xxx	Short hhh to R	Short xxx to R
Wye	Wye	Short hh to hhh	Short xx to xxx	Open hhh to hh	Open xxx to xx
Wye	Solidly grounded wye	Short hh to hhh	Short xx to xxx	Open hhh to hh	Short xx to xxx
Wye	Wye (grounded through Z_{gnd})	Short hh to hhh	Short xx to xxx	Open hhh to hh	Connect xx to xxx through $3Z_{gnd}$
Solidly grounded wye	Solidly grounded wye	Short hh to hhh	Short xx to xxx	Short hh to hhh	Short xx to xxx
Solidly grounded wye	Wye (grounded through Z_{gnd})	Short hh to hhh	Short xx to xxx	Short hh to hhh	Connect xx to xxx through $3Z_{gnd}$
Wye (grounded through Z_{gnd})	Wye (grounded through Z_{gnd})	Short hh to hhh	Short xx to xxx	Connect hh to hhh through $3Z_{gnd}$	Connect xx to xxx through $3Z_{gnd}$

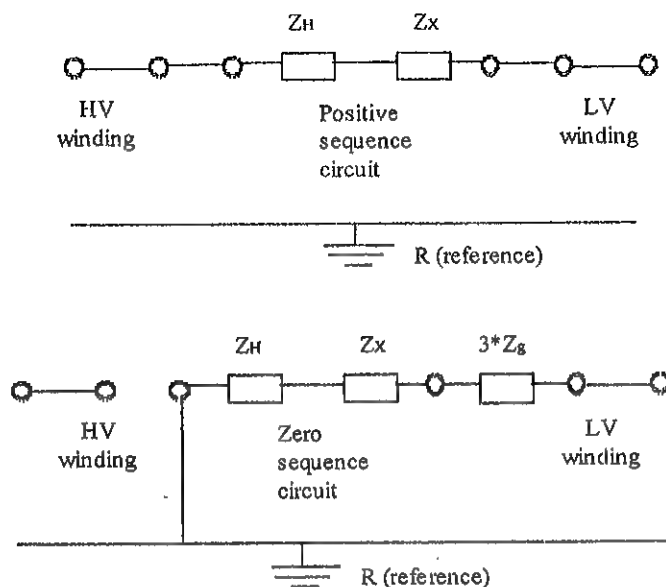


Figure 11-2b—Example sequence networks for delta to impedance grounded wye transformer connection

Figure 11-2c shows the diagram used to explain the sequence networks for three-winding (three-phase) transformers. The connections are based upon the information given in Table 11-2. For example, assume the following transformer connections: a delta (primary winding, h) to solidly grounded wye (secondary winding, x) connection with the tertiary winding (t) connected in delta. The positive and negative sequence network would consist of shorting “hh to hhh,” “xxx to xx,” and “ttt to tt.” The zero sequence network would have the “h” and “t” windings with “hh to hhh” and “tt to ttt” open and with “hhh” and “ttt” shorted to reference. The secondary would have “xxx” connected to “xx” through a zero impedance branch.

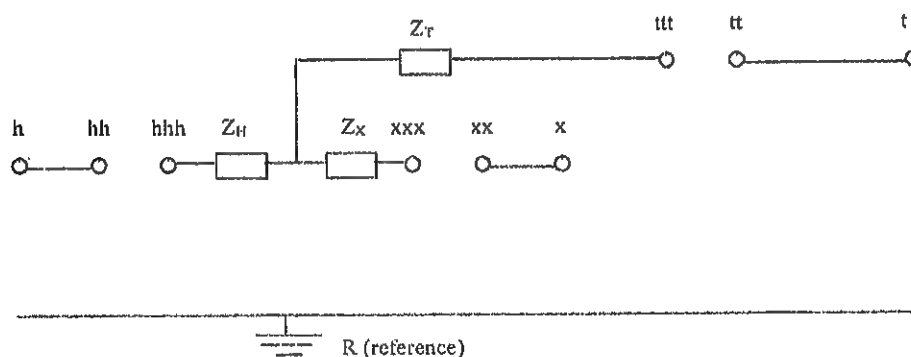


Figure 11-2c—Sequence networks for transformers with tertiary windings

11.5 Connection of sequence networks

The connections of the sequence networks for three-phase, line-to-ground, line-to-line, and double line-to-ground faults are given in Figure 11-3a, Figure 11-3b, Figure 11-3c, and Figure 11-3d. The diagrams show the direction and location of the sequence currents and the sequence voltages. It is important to recognize the defined positive directions for current flow and voltage polarity. Attention to the defined convention is necessary so that the correct phase values can be obtained from the sequence values. The references at the end of this chapter can be consulted for more detail on the development of the sequence network connection or to learn how to calculate other unbalances such as an open phase.

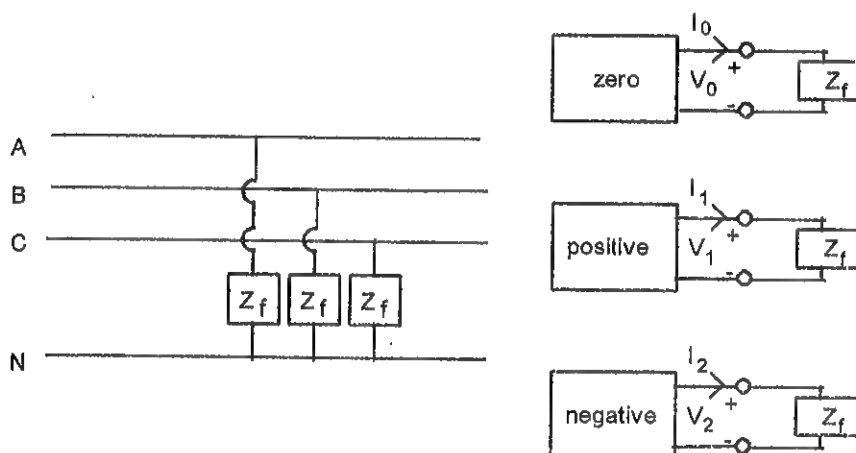


Figure 11-3a—Connection of sequence networks for a three-phase fault

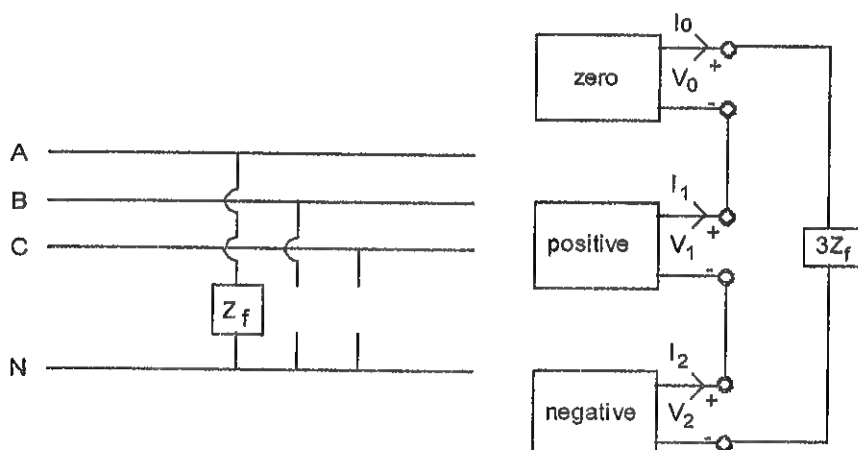


Figure 11-3b—Connection of sequence networks for a line-to-ground fault

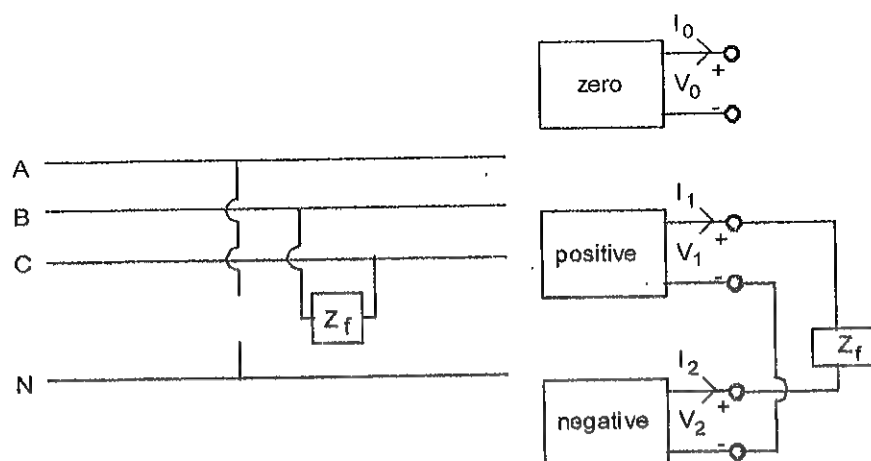


Figure 11-3c—Connection of sequence networks for a line-to-line fault

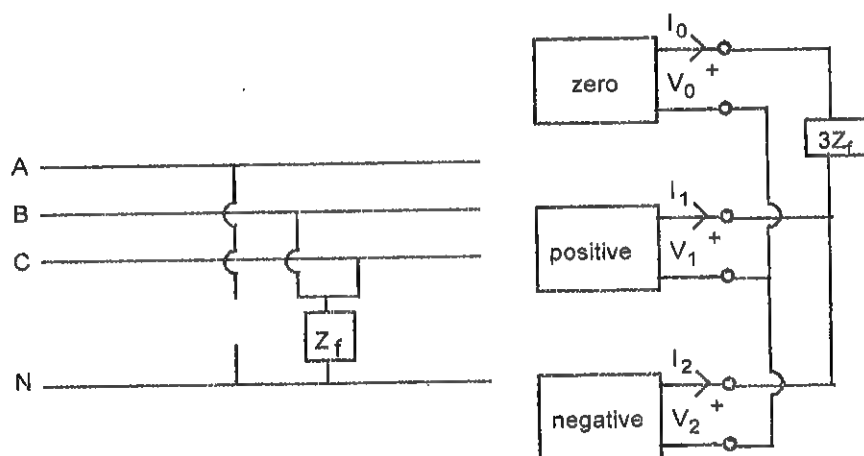


Figure 11-3d—Connection of sequence networks for a double line-to-ground fault

11.6 Sample calculations

For illustration purposes, a first cycle line-to-ground and a line-to-line fault will be calculated at the primary and secondary of transformer T-14. The circuit impedances and equivalents from the three-phase fault conditions in Chapter 9 will be used to reduce the amount of network reduction required for the sample calculations. The condition represented has all motors and generators in service. Figure 11-4 shows the positive and zero sequence networks for feeder M. In this case, the positive and negative sequence impedances will be assumed to be equal. Because the main bus has a generator connected

to it, the negative sequence impedance would in reality be slightly different in the MILL-2 bus equivalent. Because the generator negative sequence impedance and the positive sequence subtransient impedance are approximately equal for a first cycle calculation, the fault error would be small. The difference would become greater for fault calculations that are beyond the first cycle.

The positive sequence diagram of Figure 11-4 has two equivalents that were made and used in the sample calculations of Chapter 9. The equivalent on BUS 4 is the total mill excluding feeder M. This includes the utility source with 03:MILL-1 connected, generator 2, and other 04:MILL-2 feeders. The second equivalent is the sub-feeder P, which includes transformer T-13 with its motors and cable connection. The zero sequence diagram is complete and does not include any equivalents. The delta-wye transformer T-2 isolates 04:MILL-2 ground currents from the rest of the network because no ground currents on the 13.8 kV side will flow on the 69 kV side of the transformer.

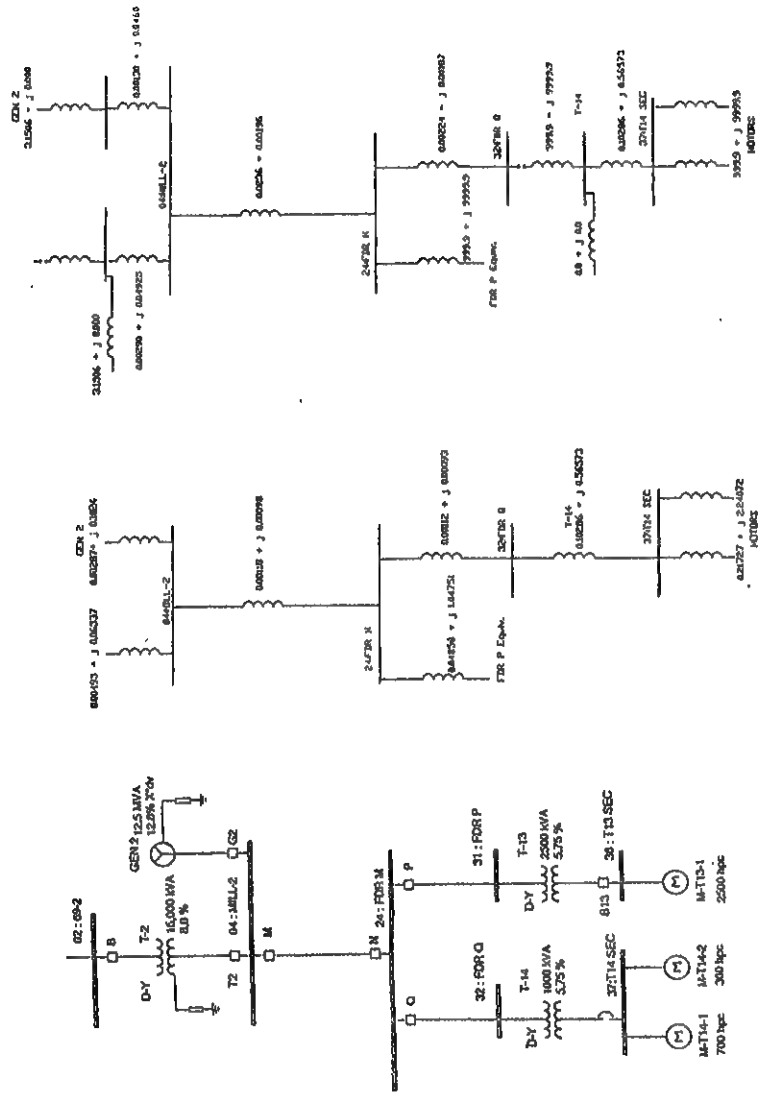
For both the line-to-ground and line-to-line faults, the positive sequence network will have to be reduced at the proposed fault points. In this case, the fault points will be buses 32:FDR Q and 37:T14 SEC. The network reduction follows the sequence networks in Figure 11-4.

Positive sequence network reduction

0.00494 + j0.06537 Equiv. on Mill-2 (Chap 9, Exam1, Item j)	(1P)
0.00287 + j0.10240 Generator #2	(2P)
0.00182 + j0.03990 Parallel (1P) and (2P)	(3P)
<u>0.00118 + j0.00098</u> Feeder M Cable C-M1	(4P)
0.00300 + j0.04088 Sum of (3P) and (4P)	(5P)
0.04858 + j1.04751 Feeder P equiv.	(6P)
0.00283 + j0.03934 Parallel (5P) and (6P) for equivalent on bus 24:FDR M	(7P)
<u>0.00112 + j0.00093</u> Cable C-M3	(8P)
0.00395 + j0.04027 Sum (equiv. from bus 4:MILL-2 to the transformer primary)	(9P)

The equivalent of the motor on T14 Sec and transformer needs to be included.

0.2460 + j2.9523 Motor M-T19-1	(10P)
1.8593 + j9.2963 Motor M-T19-2	(11P)
0.2146 + j2.2407 Motor equivalent (parallel (10P) and (11P))	(12P)
<u>0.10286 + j0.5657</u> Transformer T-14	(13P)
0.32012 + j2.8064 Transformer plus motor equivalent (sum of (12P) and (13P))	(14P)
0.00390 + j0.0397 Positive sequence equivalent at T-14 pri. (parallel (9P) and (14P))	(15P)



One-line Diagram Positive Sequence Network Zero Sequence Network

Figure 11-4—One-line diagram and sequence network for feeder M

For the positive sequence equivalent on T-14 secondary, add T-14 transformer impedance to the equivalent in item (9P) and in parallel with the motor equivalent.

$$0.00395 + j0.04027 \quad (9P)$$

$$\underline{0.10286 + j0.56570} \quad \text{Transformer T-14} \quad (13P)$$

$$0.10681 + j0.60597 \quad \text{Sum (equivalent from Bus 4:MILL-2 to transformer secondary)} \quad (16P)$$

$$0.07584 + j0.47749 \quad \text{Total positive sequence on the 480 V Bus 37:T14SEC} \quad (17P)$$

Parallel equivalent of (12P) and (16P)

Zero sequence network reduction

The same network reduction procedure is followed for the zero sequence network beginning with the ground sources on the incoming transformer T-2 and generator 2. The zero sequence impedance of the resistor is three times its given value because during a ground fault, currents in the three phases flow through it (see Figure 11-1). Note that $\text{Resistor}_{pu} = 3 \times \text{ohm} \times \text{Base MVA} / \text{kV}^2 = 3 \times 20 \times 10 / 13.8^2 = 3.1506$.

$$3.1506 + j0.0000 \quad \text{Grounding resistor on T-2} \quad (1G)$$

$$\underline{0.0029 + j0.04925} \quad \text{Transformer T-2} \quad (2G)$$

$$3.1535 + j0.04925 \quad \text{Sum (1G) and (2G)} \quad (3G)$$

$$3.1506 + j0.0000 \quad \text{Grounding resistor on GEN-2} \quad (4G)$$

$$\underline{0.0029 + j0.04925} \quad \text{Generator GEN-2} \quad (5G)$$

$$3.1535 + j0.04925 \quad \text{Sum (4G) and (5G)} \quad (6G)$$

The parallel equivalent of the two grounding sources (3G) and (6G) is:

$$1.57635 + j0.02389 \quad (7G)$$

$$0.00236 + j0.00196 \quad \text{Cable C-M1} \quad (8G)$$

$$\underline{0.00224 + j0.00187} \quad \text{Cable C-M2} \quad (9G)$$

$$1.58095 + j0.02772 \quad \text{Sum (7G), (8G), and (9G)} \quad (10G)$$

$$9999.9 + j99999.9 \quad \text{Equivalent of motors and transformer to 13.8 kV} \quad (11G)$$

The result is the zero sequence equivalent to T-14 primary. Note that the motors and transformer on sub-feeder P do not enter into the equivalent at bus 24:FDR M because of the delta primary winding (open circuit for zero sequence) of transformer T-13. The motors and transformer of T-14 are not included for the same reason.

For this one-line diagram, the equivalent ground source on the secondary of the transformer is the transformer zero sequence impedance. The motors are not grounded and do not become part of the zero sequence network.

$$0.10286 + j0.56573 \quad \text{Transformer T-14} \quad (12G)$$

$$9999.9 + j99999.9 \quad \text{Equivalent of motors} \quad (13G)$$

Once the equivalents have been made, the sequence networks can be connected together for the desired fault type. See Figure 11-3 for the appropriate connections and the direction of the sequence currents. The positive, negative, and zero sequence networks are connected in series for the line-to-ground faults as shown in Figure 11-5 and the positive and negative sequence networks are connected in parallel for the line-to-line fault.

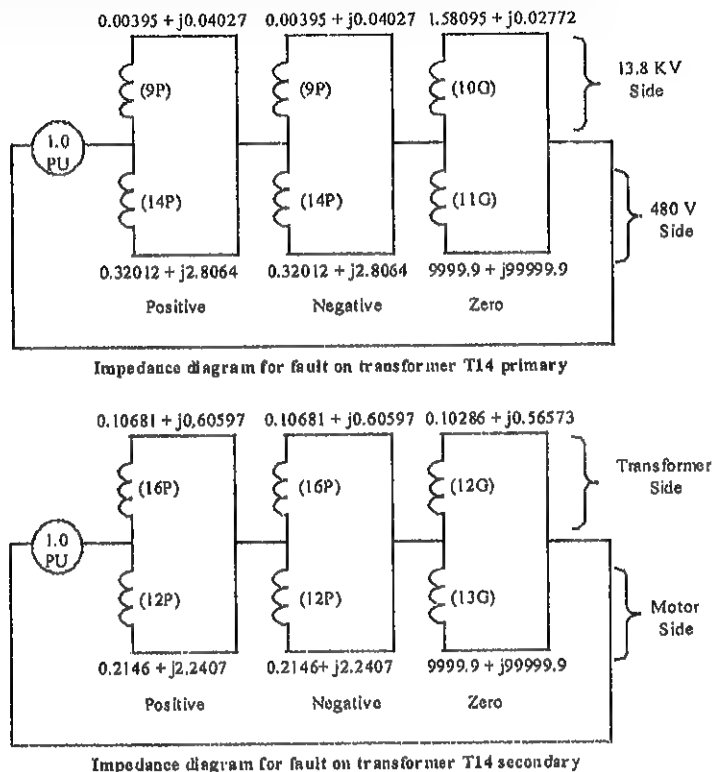


Figure 11-5—Connection of sequence network for line-to-ground faults

11.6.1 Line-to-ground fault calculation

Calculating a line-to-ground fault on the primary of transformer T-14 requires the positive, negative, and zero sequence network equivalents at the primary of the transformer as determined previously. Because in this example the positive and negative sequence networks will be assumed equal, the equivalent of item (15P) is used. The equivalent of the zero sequence network is given in (10G). The three sequence networks are connected in series as shown in Figure 11-3b.

$0.00390 + j0.03970$ Positive sequence

$0.00390 + j0.03970$ Negative sequence

$1.58095 + j0.02772$ Zero sequence

$1.58875 + j0.10712$ Sum

$$I_0 = \frac{E}{Z} = \frac{1}{1.58875 + j0.10712} = 0.6280 \angle -3.86^\circ \text{ p.u.}$$

$$I_0 = \frac{0.62801 \times 10}{13.8 \times 1000 \times 1.732} = 262.7 \text{ A}$$

Using Equation (3.16) from Chapter 3, the ground fault current can be calculated. For the current into the fault, the equation will yield the following 13.8 kV current:

$$I_a = I_{a0} + I_{a1} + I_{a2}$$

$$I_b = I_{a0} + I_{a1} \angle 240^\circ + I_{a2} \angle 120^\circ$$

$$I_c = I_{a0} + I_{a1} \angle 120^\circ + I_{a2} \angle 240^\circ$$

$$I_a = I_{\text{fault}} = 3I_0 = 788.2 \text{ A}$$

$$I_b = 0$$

$$I_c = 0$$

Often on resistance grounded systems, a rigorous line-to-ground fault calculation is not made. The sum of the current rating of each resistor is used. For the 20 ohm resistors in the above example, the maximum fault current would be $13\,800 / (1.732 \times 20) = 398.4$ amperes per resistor or 796.8 amperes total. This is only 1% higher than the 788.2 amperes calculated by the more rigorous method and well within the tolerance of any relay setting.

Figure 11-6 shows the division of the sequence current in each of the networks for a fault on the transformer primary. The division was determined by the equivalent sequence impedance as given in Figure 11-5.

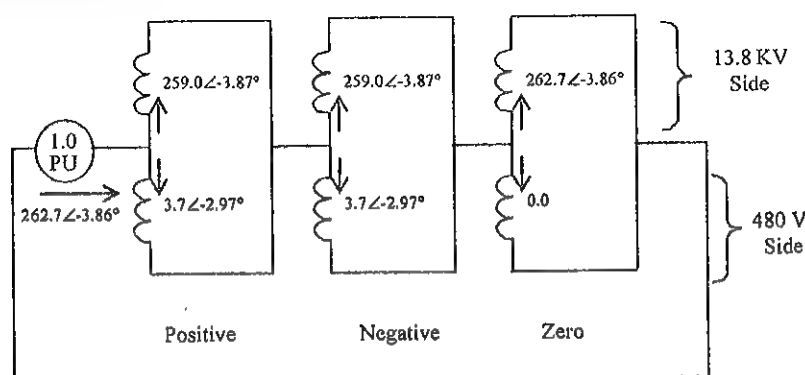


Figure 11-6—Division of sequence currents for a line-to-ground fault on T-14 transformer primary

Using Equation (3.16), the line currents on each side of the transformer can be calculated. The phase A, B, and C currents on the primary side of the transformer are determined by the sequence currents shown on the 13.8 kV side of the transformer.

The currents on the 480 V side are calculated by the same equations. However, because the delta-wye transformer shifts the secondary side by -30° degrees with respect to the primary, the angle has to be included in the sequence components on the secondary. The positive sequence current on the secondary has angle 30° subtracted from it, the negative sequence current on the secondary has angle 30° added to it, and the zero sequence is not shifted. The calculation of phase values can only take place after these angles have been introduced in the sequence values. The phase currents are shown in Figure 11-7. Note that the line-to-ground fault on the transformer primary appears as a line-to-line fault on the secondary.

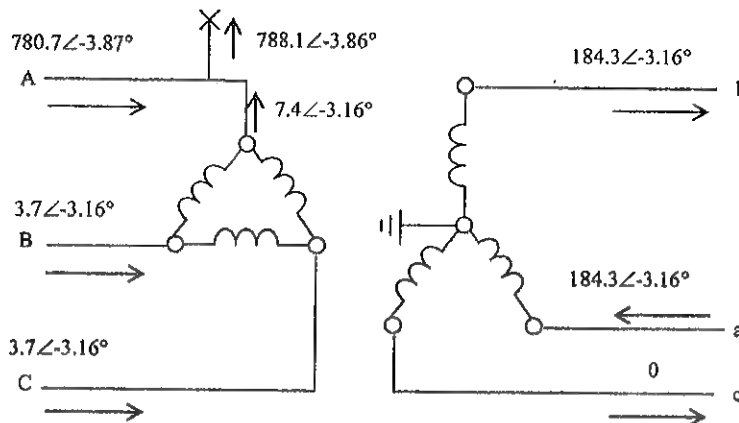


Figure 11-7—Line currents for a line-to-ground fault on T14 transformer primary

Calculating a line-to-ground fault on the secondary of transformer T-14 requires the positive, negative, and zero sequence network equivalents at the secondary of the transformer as determined previously. In this example the positive and negative sequence networks will be assumed equal and the equivalent of item (17P) is used. The equivalent of the zero sequence network is given in 12G.

0.07132 + j0.47698 Positive sequence

0.07132 + j0.47698 Negative sequence

0.10286 + j0.56573 Zero sequence

0.24550 + j1.51969 Sum

$$I_0 = \frac{E}{Z} = \frac{1}{1.24550 + j1.51969} = 0.64960 \angle -80.8^\circ \text{ p.u.}$$

$$I_0 = \frac{0.6496 \times 10}{0.48 \times 1000 \times 1.732} = 8174 \text{ A}$$

Using Equation (3.16) from Chapter 3, the ground fault current can be calculated. For the current into the fault the equation will yield the following 480 V current:

$$I_a = I_{\text{fault}} = 3I_0 = 24.523 \text{ kA}$$

$$I_b = 0$$

$$I_c = 0$$

Figure 11-8 shows the division of the sequence current in each of the networks for a fault on the transformer secondary. The division was determined by the equivalent sequence impedance as given in Figure 11-5.

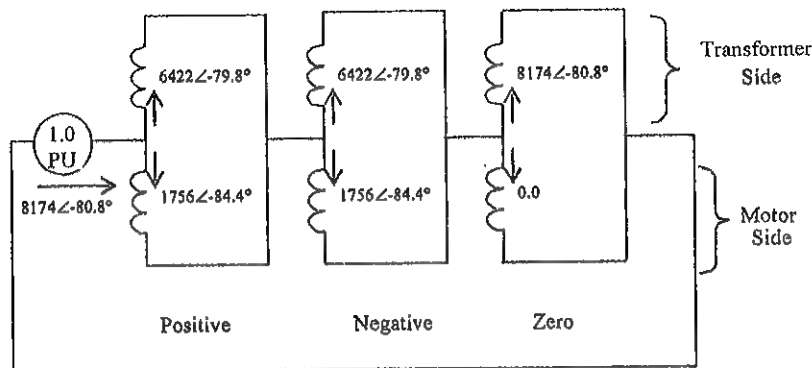


Figure 11-8—Division of sequence currents for a line-to-ground fault on T14 transformer secondary

The line current flows on each side of the transformer are shown in Figure 11-9. The line currents on the primary side of the transformer are calculated using Equation (3.16).

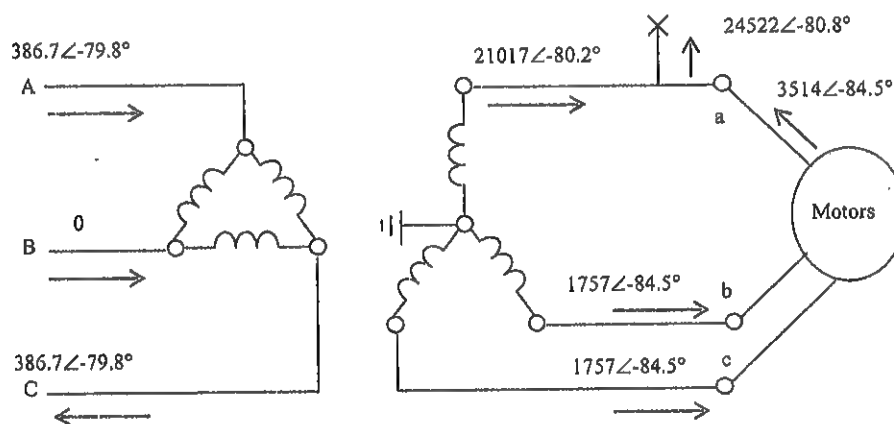


Figure 11-9—Line currents for a line-to-ground fault on T14 transformer secondary

The phase a, b, and c currents on the secondary side of the transformer are determined by the sequence currents shown on the 480 V side of the transformer. However, because the delta-wye transformer shifts the primary side by 30° degrees with respect to the secondary, the angle has to be included in the sequence components on the primary. The positive sequence current on the primary has angle 30° added to it, the negative sequence current on the primary has angle 30° subtracted from it, and the zero sequence is not shifted. The calculation of phase values can only take place after these angles have been introduced in

the sequence values. The line-to-ground fault on the transformer secondary appears as a line-to-line fault to the 13.8 kV system.

11.6.2 Line-to-line fault calculation

Calculating a line-to-line fault on the primary of transformer T-14 requires the positive and negative sequence networks. The zero sequence network is not required. In this example the positive and negative sequence networks will be assumed equal and the equivalent of item (15P) is used. Also note in Figure 11-3c that for a line-to-line fault the negative sequence current is the reverse of the positive sequence current flow.

$$0.00390 + j0.03970 \quad \text{Positive sequence}$$

$$\underline{0.00390 + j0.03970} \quad \text{Negative sequence}$$

$$0.00780 + j0.07940 \quad \text{Sum}$$

$$I_0 = \frac{E}{Z} = \frac{1}{0.00780 + j0.07940} = 12.534 \angle -84.39^\circ \text{ p.u.}$$

$$I_0 = \frac{12.534 \times 10}{13.8 \times 1000 \times 1.732} = 5244 \text{ A}$$

$$I_2 = I_1 = -5244 \text{ A}$$

$$I_0 = 0$$

Using Equation (3.16) from Chapter 3, the phase-to-phase fault current can be calculated. For the current into the fault, the equation will yield the following:

$$I_a = 0$$

$$I_b = 9083 \text{ A}$$

$$I_c = 9083 \text{ A}$$

Often for line-to-line faults, a rigorous calculation is not made. The line-to-line fault current is 86.6% of the three-phase fault current when the positive and negative sequence networks are equal.

Figure 11-10 shows the division of the sequence currents in each of the networks for a fault on the transformer primary. The division was determined by the equivalent sequence impedance as given in Figure 11-5.

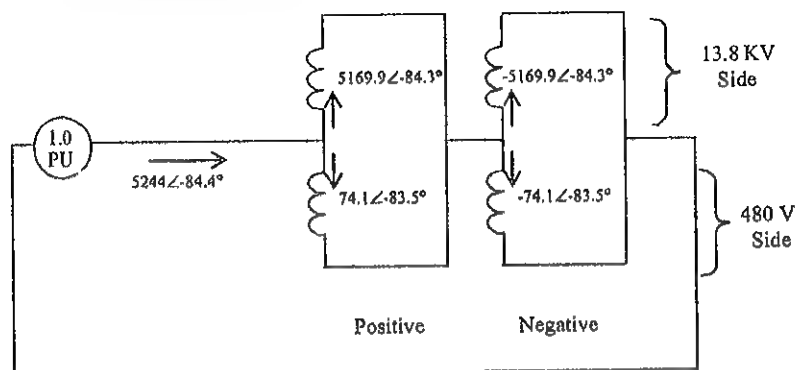


Figure 11-10—Division of sequence currents for a line-to-line fault on T14 transformer primary

Using Equation (3.16), the line currents on each side of the transformer can be calculated. The phase A, B, and C currents on the primary side of the transformer are determined by the sequence currents shown on the 13.8 kV side of the transformer. The currents on the 480 side are calculated by the same equations. However, because the delta-wye transformer shifts the secondary side by -30° degrees with respect to the primary, the angle has to be included in the sequence components on the secondary. The positive sequence current on the secondary has angle 30° subtracted from it, the negative sequence current on the secondary has angle 30° added to it, and the zero sequence is not shifted. The calculation of phase values can only take place after these angles have been introduced in the sequence values. The phase currents are shown in Figure 11-11.

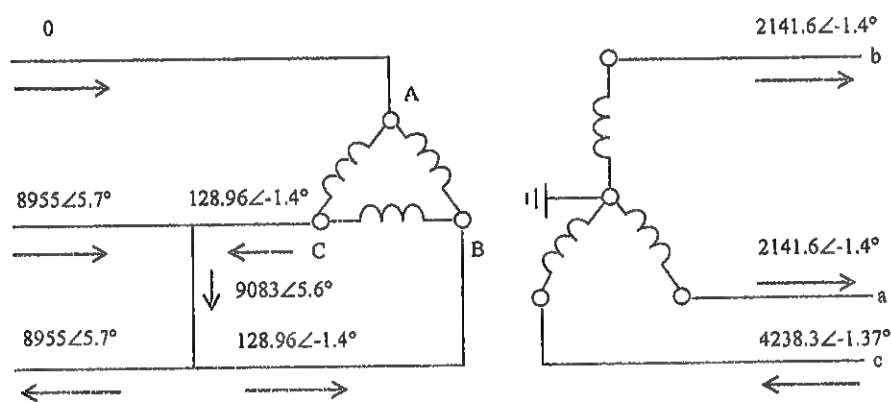


Figure 11-11—Line currents for a line-to-line fault on T14 transformer primary

Calculating a line-to-line fault on the secondary of transformer T-14 requires the positive and negative sequence network equivalents at the secondary of the transformer as determined previously. Again in this example, the positive and negative sequence networks will be assumed equal and the equivalent of item 17P is used.

$0.07584 + j0.47749$ Positive sequence

$0.07584 + j0.47749$ Negative sequence

$0.15169 + j0.95498$ Sum

$$I_1 = \frac{E}{Z} = \frac{1}{0.15169 + j0.95498} = 1.0342 \angle -80.97^\circ \text{ p.u.}$$

$$I_1 = \frac{1.0342 \times 10}{0.48 \times 1000 \times 1.732} = 12439.5 \text{ A}$$

$$I_2 = I_1 = -12439.5 \text{ A}$$

Using Equation (3.16) from Chapter 3, the line fault current can be calculated. For the current into the fault, the equation will yield the following:

$$I_a = 0$$

$$I_b = 21.55 \text{ kA}$$

$$I_c = 21.55 \text{ kA}$$

Figure 11-12 shows the division of the sequence current in each of the networks for a fault on the transformer secondary. The division was determined by the equivalent sequence impedance as given by items (12P) and (15P) for the positive and negative sequence networks.

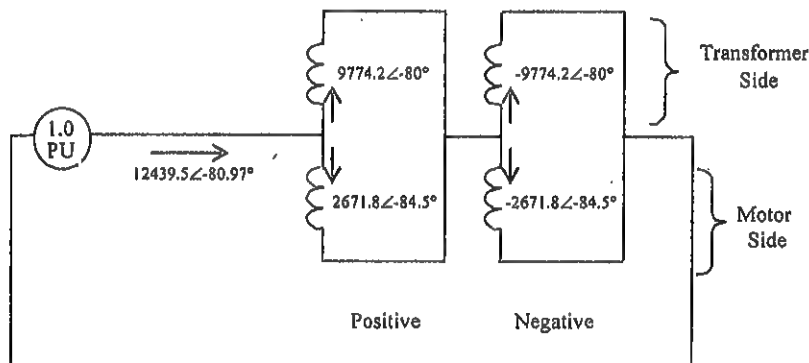


Figure 11-12—Division of sequence currents for a line-to-line fault on T14 transformer secondary

The line current flows are shown in Figure 11-13. The line currents on the primary side of the transformer can be calculated using Equation (3.16). The phase a, b, and c currents on the secondary side of the transformer are determined by the sequence currents. However, because the delta-wye transformer shifts the primary side by 30° degrees with respect to the secondary, the angle has to be included in the sequence components on the primary. The positive sequence current on the primary has angle 30° added to it, the negative sequence current on the primary has angle 30° subtracted from it, and the zero sequence is not shifted. The calculation of phase values can only take place after these angles have been introduced in the sequence values.

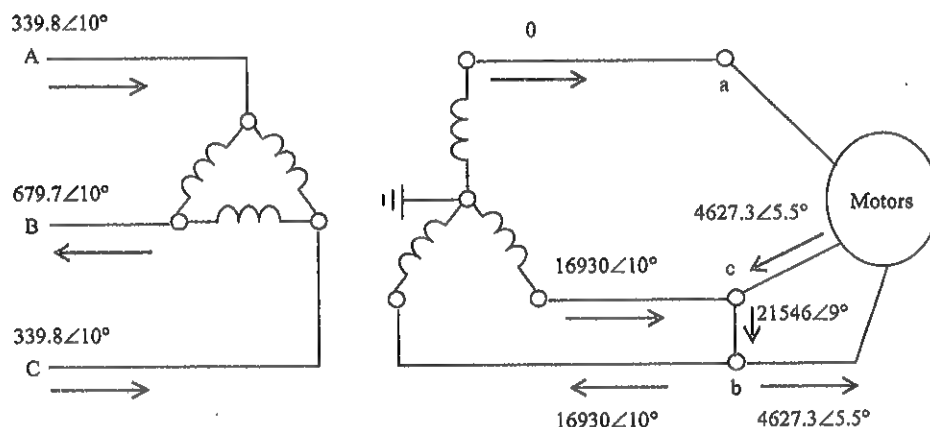


Figure 11-13—Division of line currents for a line-to-line fault on T14 transformer secondary

11.7 Conclusions

In this chapter, the analytical methods and techniques for calculating unbalanced short-circuit currents have been introduced. Of primary importance is the concept of interconnecting sequence networks (in either full or reduced form) to simulate the unbalanced effects of different fault types. The calculation methods, based on the method of symmetrical components, have been presented, but it has been shown that such rigorous calculations are not always necessary. As was discussed, single line-to-ground fault currents can often be found by considering only the system grounding impedances while the line-to-line fault currents are typically very nearly equal to 86.6% of the three-phase fault current values.

11.8 Normative references

The following referenced documents are indispensable for the application of this document. For dated references, only the edition cited applies. For undated references, the latest edition of the referenced document (including any amendments or corrigenda) applies.

IEC 909, Short-Circuit Current Calculations in Three-Phase A.C. Systems.²

IEEE Std C37.010TM-1999, IEEE Application Guide for AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis.^{3, 4}

IEEE Std C37.13TM-1990 (Reaff 1995), IEEE Standard for Low-Voltage AC Power Circuit Breakers Used on Enclosures.

11.9 Bibliography

[B1] Beeman, Donald, *Industrial Power Systems Handbook*. McGraw-Hill.

[B2] Brown, Homer E., *Solution of Large Networks By Matrix Methods*. Wiley Book.

[B3] Calabrese, G. O., *Symmetrical Components*. The Ronald Press Company, 1959.

[B4] IEEE Std 141TM-1993, Electric Power Distribution for Industrial Plants (*IEEE Red Book*).

[B5] IEEE Std 242TM-2001, IEEE Recommended Practice for Protection and Coordination of Industrial and Commercial Power Systems (*IEEE Buff Book*).

[B6] Rothe, F. S. *An Introduction to Power System Analysis*. Wiley Book.

[B7] Wagner, C. F., and R.D. Evans, *Symmetrical Components*. McGraw-Hill Book Company, 1933.

[B8] Westinghouse Electrical Transmission & Distribution Reference Book.

²IEC publications are available from the Sales Department of the International Electrotechnical Commission, Case Postale 131, 3, rue de Varembe, CH-1211, Genève 20, Switzerland/Suisse (<http://www.iec.ch/>). IEC publications are also available in the United States from the Sales Department, American National Standards Institute, 11 West 42nd Street, 13th Floor, New York, NY 10036, USA.

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Chapter 12

Short-circuit calculations under international standards

12.1 Introduction

Short-circuit calculations for industrial and commercial power systems are, as a rule, performed in North America in accordance with the ANSI-approved standards (see Chapter 8), originally introduced some decades ago. Ever since, they experienced several revisions to reflect harmonization between AC/DC decrement modeling and various breaker-rating structures. They are, to this day, widely accepted as an important and reliable computational tool for performing short-circuit calculations.

The purpose of this chapter is to outline how short-circuit calculations are addressed by other International standards. Several fault calculation guidelines can be found worldwide ranging from naval standards, used by shipbuilders for electrical installations on commercial and/or military vessels to “recommendations” used by engineers in several European countries. A commonly used IEC standard for this type of isolated system is IEC 61363-1:1998.¹ Until the mid 1980s one of the prevailing European standard was the German VDE-0102 (IEC 60909-0:2001, IEC 61362-1:1998), covering both industrial and utility electric power systems. The work undertaken under the auspices of the International Electrotechnical Commission during the 1980s, brought to fruition the IEC 60909 standard. IEC 60909 strongly resembles the earlier VDE-0102 guidelines and is currently acknowledged as the accepted European standard.

Since its introduction in 1988, IEC 60909-0:2001, served as platform for other International standards, such as the Australian standard AS-3851, issued in 1991. This chapter will primarily focus on the IEC 60909 since it, by far, constitutes the main alternative to the North American ANSI standard. The treatment given here serves the purpose of providing only the most salient conceptual and computational aspects featured by the IEC 909 standard. The user is therefore strongly advised to refer to the standard itself (IEC 909:1988, IEC 61363-1:1998) for further details. This chapter addresses techniques pertinent to three-phase short circuits only. The interested reader should consult the standard itself for considerations related to asymmetrical short circuits.

12.2 System modeling and methodologies

IEC 60909-0:2001 covers three-phase ac electric power systems, operating at either 50 Hz or 60 Hz, up to voltages of 230 kV, including low-voltage systems. The standard addresses three-phase, line-to-ground, line-to-line and double-line-to-ground short circuits.

¹Information on normative references can be found in 12.11.

Despite the fact that rigorous calculation techniques, like the “Helmholtz superposition” method (see Figure 12-1) or “time-domain” analysis are not excluded, the IEC 60909 standard recommends the simpler “equivalent source” technique.

The “equivalent source” technique, assumes only one source exciting the network at the short-circuit location, while all other contributing sources are rendered inactive (see Figure 12-2).

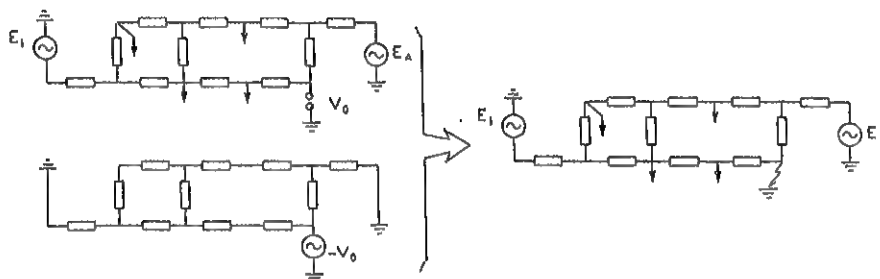


Figure 12-1—The superposition analysis principle

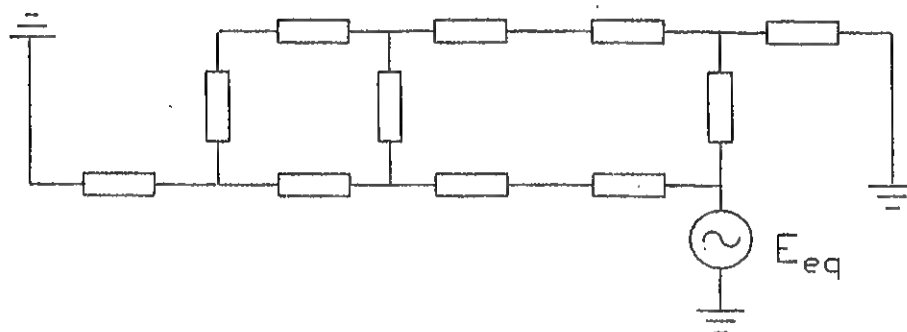


Figure 12-2—The “equivalent source” at the fault location

The method of symmetrical components, with explicit negative sequence representation, is used in conjunction with the equivalent voltage source at the fault location, for calculating the short-circuit currents. Since all other current sources are considered inactive, network feeders (utility interconnection points), synchronous, asynchronous machines and regenerative SCR drives are represented by their equivalent internal impedances. The magnitude of the equivalent voltage source, is calculated as the product of the voltage factor C and the nominal system line-to-ground voltage at the fault location. System shunts (line/cable capacitances, shunt capacitors, shunt inductors) and static loads are ignored in the positive and negative sequence networks. However, IEC 60909-0 recommends that line capacitances be included in the zero sequence network, if the system

neutral is not solidly grounded. If the system neutral is solidly grounded, neglecting the zero sequence system shunts leads to conservative results and is not necessary to consider them. The three-phase transmission lines and cables are assumed to be balanced, with no intersequence coupling, in order to justify the use of symmetrical components. The sequence networks are reduced to equivalent impedances at the fault location for subsequent calculations. Sequence impedances for non-rotating equipment are considered equal for positive. Negative sequence and transformers are, in general, to be treated with their taps in the main position.

In modeling AC decrement, IEC 60909-0:2001 makes the distinction between short circuits “far from generator” and short circuits “near generator.” In calculating peak short-circuit currents and modeling DC decrement, the standard distinguishes whether the fault current arrives at the fault from “meshed” or “non meshed” systems. In calculating steady-state fault currents, IEC 60909 recommends that it may be necessary to consider the excitation systems of synchronous machinery (including synchronous motors under special circumstances). All the above considerations are important and command particular calculation techniques.

In what follows, the techniques for calculating maximum and minimum short-circuit currents, for all duty types, are given for the cases the standard considers as generic. The outline, notation, and sequence of presentation adopted in the standard itself has been preserved as much as possible for ease of reference. The material given here conveys only the basic computational and modeling aspects. For more details, IEC 60909-0 itself must be consulted.

12.3 Voltage factors

The “equivalent source” technique adopted in IEC 60909-0:2001 recommends applying a voltage factor C (C_{\max} or C_{\min}) to the prefault nominal system voltage, in order to obtain the voltage magnitude of the equivalent source at the fault location. These voltage factors, obtained from IEC 909:1988 are reproduced, for ease of reference, in Table 12-1 for various voltage levels. They are important in distinguishing between maximum and minimum short-circuit currents and are introduced in order to account for prefault system loading (resulting in varying exploitation voltages), off-nominal transformer taps, excitation of generators etc.

12.4 Short-circuit currents per IEC 60909

The definitions that follow, have been reproduced from the IEC 909 standard for ease of reference. The notation used by the standard has also been preserved and will be adhered to.

Maximum short-circuit currents, I_{\max} —The maximum short-circuit currents are used to evaluate the Interrupting and Peak requirements of circuit breakers for subsequent switchgear selection and equipment rating. The appropriate voltage factor, C_{\max} , should be used when calculating them, as shown in Table 12-1.

Table 12-1—IEC 909 prefault voltage factors

Nominal voltage, V_n	Max. fault currents, C_{max}	Min. fault currents, C_{min}
Low voltage 100 V to 1000 V (IEC 60038 [B1], Table I)	1.00	0.95
a) 230 / 400 V		
b) Other voltages	1.05	1.00
Medium voltages > 1000 V, to 35 kV (IEC 60038 [B1], Table III)	1.10	1.00
High voltages > 35 kV to 230 kV (IEC 60038 [B1], Table IV)	1.10	1.00

Minimum short-circuit current, I_{min} —The minimum short-circuit currents are used to set the protective devices on the system and for run-up motor verification. The appropriate voltage factor, C_{min} , should be used when calculating them, as shown in Table 12-1.

Initial short-circuit current, I''_k —The rms value of the AC symmetrical component of a prospective (available) short-circuit current applicable at the instant of the short circuit, if the system impedances remain unchanged.

Peak short-circuit current, I_p —The maximum possible instantaneous value of the prospective (available) short-circuit current.

Symmetrical short-circuit breaking current, I_b —The rms value of an integral cycle of the symmetrical AC component of the prospective short-circuit current, at the instant of contact separation of the first pole of the switching device.

Steady-state short-circuit current, I_k —The rms value of the short-circuit current that remains after the decay of the transient phenomena.

The aperiodic component of short-circuit current, I_{dc} —The mean value between the top and bottom envelope of short-circuit current decaying from an initial value to zero.

12.5 Short circuits “far from generator”

12.5.1 Definitions and generalities

A short circuit is considered to be “far from generator” when the magnitude of the symmetrical AC component of the prospective fault current remains essentially constant with time. This condition can be intuitively visualized as perceiving the contributing sources exhibiting constant internal voltages while their impedances experience no change

with time. In other words, short circuits “far from generator” are short circuits fed from sources that can safely be assumed to possess no AC decrement of any kind (see 12.6 for similar definitions addressing short circuits “near generator”). The fault current may, nevertheless, contain an aperiodic (dc) taken into account for assessing breaker interrupting requirements and the potentially damaging mechanical effects of the short circuit currents.

12.5.2 Calculation of maximum fault currents

The computational procedures given below apply only when all of the conditions stipulated in 12.5.1 are satisfied. If this is not the case, the computational techniques for faults “near generator” should be used. Since this section addresses calculations involving no AC decrement, the concept of the Network Feeder is introduced first.

12.5.3 Network feeders

Network feeders (see Figure 12-3) are interconnection points, usually of high supply capability, exhibiting no AC decrement characteristics, typical examples being utility service entrance points. They are to be represented, for short-circuit calculations, as impedances determined by Equation (12.1):

$$Z_Q = \frac{CV_{nQ}^2}{S''_k} \quad (12.1)$$

Z_Q = Network feeder impedance

C = Voltage factor at interconnection point

V_{nQ} = Nominal system line-to-line voltage at interconnection point (kV)

S''_k = Three-phase short-circuit capacity at interconnection point (MVA)

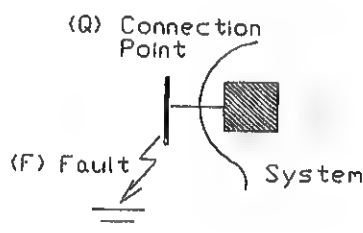


Figure 12-3—Network feeder representation

12.5.4 Initial short-circuit current calculations

Assuming that the fault is fed by a single source, it suffices to calculate the total impedance to the fault $Z_{kk} (R_k + jX_k)$. The initial short-circuit current I''_k is then given by Equation (12.2):

$$I'_{kt} = \frac{CV}{\sqrt{3}Z_{kk}} \quad (12.2)$$

If multiple non-meshed sources feed the fault (Figure 12-4), Equation (12.2) is to be used to calculate the individual contributions to the fault. The total initial short-circuit current is then calculated as the arithmetic sum of the partial currents as in Equation (12.3):

$$I_{kt} = I'_{k1} + I'_{k2} + \dots + I'_{kn} \quad (12.3)$$

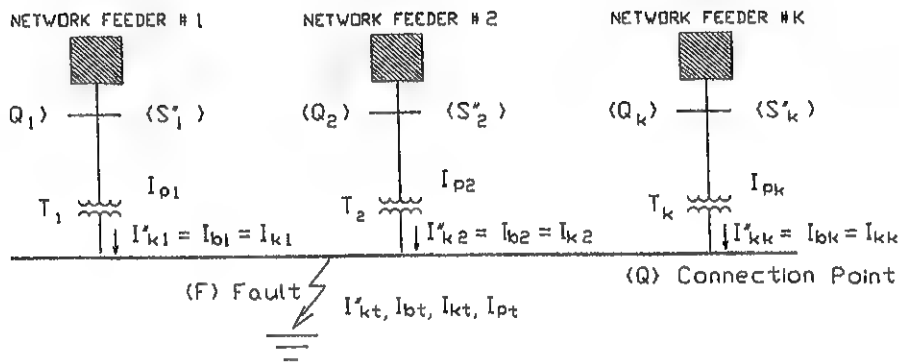


Figure 12-4—Multiple-fed fault from non-meshed sources

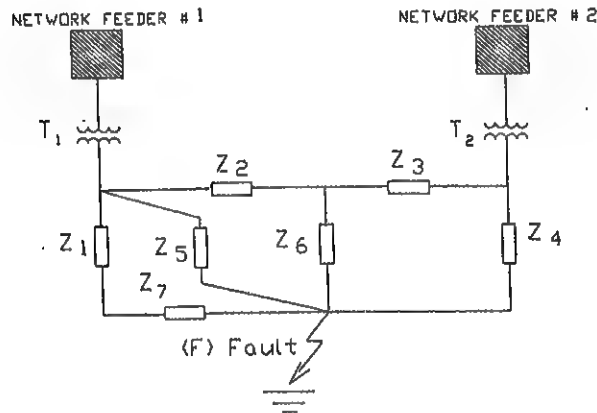


Figure 12-5—Short circuit in a meshed system

For the more general case of meshed systems (Figure 12-5), the initial short circuit is calculated using Equation (12.2), with Z_{kk} being the equivalent system impedance at the fault point. Z_{kk} must be calculated using complex network reduction i.e., by considering the branch and sources complex impedances.

12.5.5 Symmetrical breaking current

Since no AC decrement is present for short circuits “far from generator” the initial short-circuit current remains unchanged. Thus, the symmetrical breaking current, for a single-fed short circuit, equals the initial fault current.

$$I_b = I_k'' \quad (12.4)$$

The same principle extends to the case where multiple non-meshed sources feed the short circuit. Thus,

$$I_{bt} = I_{b1} + I_{b2} + \dots I_{bn}'' = I_{k1}'' + I_{k2}'' + \dots I_{kn}'' \quad (12.5)$$

Equation (12.5) remains valid for calculating the short-circuit breaking current when the fault is fed through meshed networks of general configuration.

12.5.6 Steady-state fault current

Since no AC decrement is present for “far from generation” short circuits, the steady-state fault current is equal to the initial fault current. Thus for single-fed short circuits,

$$I_k = I_k'' \quad (12.6)$$

for multiple fed non-meshed sources feeding the fault,

$$I_{kt} = I_{k1} + I_{k2} + \dots I_{kn}'' = I_{k1}'' + I_{k2}'' + \dots I_{kn}'' \quad (12.7)$$

Equation 12-7 remains valid for faults fed through meshed networks.

12.5.7 Peak fault current

IEC 909:1988 recommends calculating peak fault currents by applying a crest (peak) factor κ to the symmetrical initial fault current I_k'' , as:

$$I_p = \kappa \sqrt{2} I_k'' \quad (12.8)$$

These factors are derived under the assumption that the short circuit occurs at zero voltage and are valid for both 50 Hz and 60 Hz systems. In order to account for AC decrement, during the rise time to peak, for faults near generators and/or motors, special R/X ratios are recommended for this type of equipment (see 12.6.3 and 12.7.3). Proper calculation and application of the relevant crest factor(s) necessitates distinguishing between meshed and non meshed fault current paths as well as whether the fault is single-fed or not. A source can be considered to contribute to the fault through a non-meshed path, if its contribution is independent of any remaining connections at the fault point (see Figure 12-4).

Alternatively, a source contributes to the fault through a meshed path if its contribution is affected by other connections at the fault point (see Figure 12-5).

12.5.8 Non-meshed current paths

If the fault is single-fed, the crest factor κ is calculated as follows:

$$\kappa = 1.02 + 0.98e^{-3R/X} \quad (12.9)$$

where the X/R ratio is for the branch feeding the fault.

For the case the fault is fed by several non-meshed sources, the technique applied to the single-fed short circuit, is applied to all individual sources feeding the fault in order to calculate the individual peak currents. The total peak current is then calculated as the sum of the partial peak currents.

$$I_{pt} = I_{p1} + I_{p2} + \dots I_{pn} \quad (12.10)$$

12.5.9 Meshed current paths

IEC 909:1988 mentions three techniques for calculating the peak short-circuit current in meshed networks, namely:

- a) Dominant X/R ratio technique
- b) Equivalent X/R ratio technique
- c) Equivalent frequency technique

12.5.9.1 Dominant X/R ratio technique

This technique calculates the crest factor, as shown in Equation (12.11):

$$\kappa = 1.02 + 0.98e^{-3R/X} \quad (12.11)$$

The ratio R/X is the smallest of all branches in the network. The branches to be considered are the ones carrying together at least 80% of the fault current. A branch may be a combination of several elements in series. The crest factor κ , is limited to 1.8 for low-voltage networks.

12.5.9.2 Short-circuit location X/R technique

This technique calculates the crest factor, defined as shown in Equation (12.12):

$$\kappa_b = 1.15 \kappa \quad (12.12)$$

with calculated by Equation (12.9) but using the X/R ratio of the fault impedance Z_{kk} , i.e. the ratio X_{kk}/R_{kk} . The factor κ_b is limited to 1.8 and 2.0 for low- and high-voltage networks respectively.

12.5.9.3 Equivalent frequency technique

This technique calculates the crest factor, defined as in Equation (12.13):

$$\kappa_c = \kappa_a \quad (12.13)$$

with $X/R = (X_c/R_c)(f/f_c)$, where

- R_c = $R_{\text{eal}}\{Z_c\}$ equivalent effective resistance component, for the frequency, f_c , as seen from the fault location.
- X_c = $I_{\text{imaginary}}\{Z_c\}$ equivalent effective reactance component, for the frequency as seen from the fault location
- f_c is taken to be 20 (24) Hz for a 50 (60) Hz system.
- Z_c is the impedance seen at the fault location when the source of frequency, f_c , is the only source exciting the network.

12.5.10 Calculation of minimum fault currents

The techniques outlined in 12.5.9 remain valid with the following exceptions:

- The voltage factor, C_{min} , for the minimum fault currents is to be used.
- Select the network configuration and network feeder capacity that leads to minimum short-circuit currents. This may necessitate assuming less generating plant connected to the system.
- Neglect motors.
- The resistances of overhead lines and cables are to be calculated at the temperature attained at the end of the short circuit (higher than the normally considered 20 °C) according to Equation (12.14):

$$R_1 = R_{20} (1.0 + 0.004(\theta - 20)) \quad (12.14)$$

where

- R_{20} = conductor resistance at 20 °C
- θ = temperature in degrees Celsius at the end of the short circuit
- 0.004 = coefficient valid for copper, aluminum, and aluminum alloy

12.6 Short circuits “near generator”

12.6.1 Definition and generalities

A short circuit is considered to be “near generator” when the magnitude of the symmetrical AC component of the prospective fault current decays with time. This

condition can be perceived as viewing the internal voltages of the contributing sources remaining constant, while their impedances experience an increase in magnitude with time, at the onset of the fault. A short circuit is considered by IEC 909:1988 to be near generator if at least one synchronous machine contributes a current exceeding twice its nominal current, or synchronous and asynchronous motors contribute more than 5% of the initial short-circuit current calculated without considering any motors IEC 909:1988. Additional considerations for faults “near generator” include impedance correction factors for the generators and their accompanying transformers (if any). For faults near generator, the steady-state fault current will normally have a smaller magnitude than the breaking current, which, in turn will have a smaller magnitude than the initial fault current. Fault currents near generator may contain an aperiodic (dc) component that decays to zero from an initial value. This aperiodic component will have to be taken into account for assessing breaker interrupting requirements and the potentially damaging mechanical effects of the short-circuit currents.

12.6.2 Impedance correction factors

The impedance correction factors are used to calculate the partial short-circuit currents contributed by generators and/or power system units, while accounting for prefault loading. The IEC 909 standard distinguishes between generator and power station correction factors, as explained below.

12.6.3 Generator impedance correction factor

This impedance correction factor is used when a generator is directly connected to the system, i.e., no unit transformer is found between the generator and the power system (see Figure 12-6). For this case the correction factor, K_G , is applied to the generator subtransient impedance as follows:

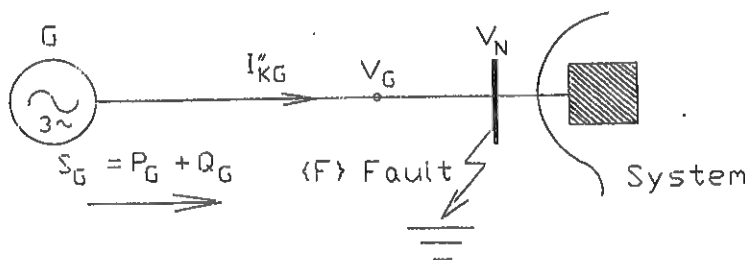


Figure 12-6—Generator impedance correction factor

$$Z_{GK} = K_G Z_G \quad (12.15)$$

where

- Z_{GK} = is the corrected generator impedance
- Z_G = is the generator impedance
- K_G = correction factor defined by Equation (12.16):

$$K_c = \frac{V_c C_{MAX}}{U_{rG}(1.0 + X''_d \sin \phi_{rG})} \quad (12.16)$$

where

V_n = Rated voltage of the system

U_{rG} = Rated generator voltage

C_{max} = Voltage factor at the connection point

X''_d = Generator subtransient reactance in p.u. of the generator rated quantities

ϕ_{rG} = Generator rated power factor angle at prefault

The correction factor, of Equation (12.16) assumes overexcited operation, $R_G \ll X''_d$ and that the generator prefault operating condition does not depart significantly from the rated one (see IEC 909:1988)

Typical R/X ratios for generator impedances, accounting for both AC and DC decrement are recommended as follows:

$$R_G = 0.05X''_d, \text{ when } U_{rG} \geq 1 \text{ kV and } S_{rG} \geq 100 \text{ MVA}$$

$$R_G = 0.07X''_d, \text{ when } U_{rG} \geq 1 \text{ kV and } S_{rG} \leq 100 \text{ MVA}$$

$$R_G = 0.15X''_d, \text{ when } U_{rG} < 1 \text{ kV}$$

12.6.4 Power station unit correction factors

A Power Station Unit (PSU) is a generator connected to the network through a dedicated transformer. In this case, the following impedance correction factors are recommended (see IEC 909:1988):

$$R_G = 0.05X''_d, \text{ when } U_{rG} \geq 1 \text{ kV and } S_{rG} \geq 100 \text{ MVA} \quad (12.17)$$

$$R_G = 0.07X''_d, \text{ when } U_{rG} \geq 1 \text{ kV and } S_{rG} \leq 100 \text{ MVA}$$

$$R_G = 0.15X''_d, \text{ when } U_{rG} < 1 \text{ kV}$$

$$K_{G,PSU} = \frac{V_c C_{MAX}}{U_{rG}(1.0 + X''_d \sin \phi_{rG})} \quad (12.18)$$

The factor $K_{G,PSU}$ will be applicable to the generator impedance, while the factor $K_{T,PSU}$ to the transformer impedance:

Equation (12.17) and Equation (12.18) apply under the condition that $U_q = U_{nQ}$ and $U_G = U_{rG}$ (see also Figure 12-6), with U_q being the operating voltage at the high-voltage

side of the transformer; U_{nQ} being the rated voltage at this point; U_G being the operating generator voltage at its terminals; and U_{tG} the rated generator voltage.

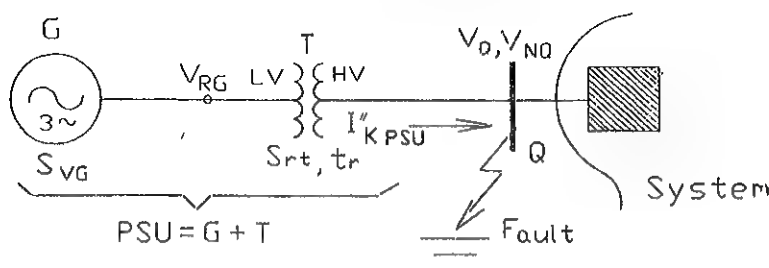


Figure 12-7—Fault on the high-voltage side of power system unit

Alternatively, for short circuits on the high-voltage side of a dedicated generator transformer (see Figure 12-7), a different correction factor treating the generator and transformer as one entity is recommended.

The correction factor for the PSU is shown in Equation (12.19):

$$Z_{PSU} = K_{PSU} (T_r^2 Z_G + Z_{THV}) \quad (12.19)$$

where

Z_{PSU} = Corrected PSU impedance

K_{PSU} = PSU impedance correction factor

T_r^2 = Rated transformer voltage ratio V_{Ht}/V_{Lt}

Z_G = Generator impedance referred to HV side

Z_{THV} = Rated Transformer Impedance referred to HV side

(12.20)

$$K_{G,PSU} = \frac{T_r^2 C_{MA}}{T_r^2 (1.0 + [X_d'' - X_T] \sin(\phi_{rG}))} = \frac{U_{nQ}^2 U_{rTLV}^2 C_{MAX}}{U_{nQ}^2 U_{rTLV}^2 (1.0 + [X_d'' - X_T] \sin(\phi_{rG}))}$$

Equation (12.20) rests on the assumptions that the generator is operated near the rated point and that the transformer rated power is nearly equal to the generator rated power (see IEC 909:1988 for more details).

U_{rTHV} = Rated transformer voltage (high-voltage side)

U_{rTLV} = Rated transformer voltage (low-voltage side)

X_T = Transformer p.u. reactance

12.6.5 Calculation of generator maximum Initial fault currents

The initial short-circuit currents are to be calculated as in the case of short-circuits currents “far from generation.” The impedance correction factors for generators and/or power station units must be taken into account.

12.6.6 Calculation of generator peak short-circuit currents

Peak fault currents are to be calculated in the same fashion as for the case of short circuits “far from generation”. The distinctions made earlier between single-fed and multiple-fed short circuits and on whether the fault path is meshed or non, apply here as well. The generator and/or PSU impedances used must properly take into account the pertinent correction factors as in the case of the initial fault currents.

12.6.7 Calculation of generator symmetrical breaking currents

The decay of a generator symmetrical short-circuit current, for a fault at its terminals, is quantified by virtue of the factor μ as follows in Equation (12.21):

$$I_b = \mu I_k'' \quad (12.21)$$

where

- I_b = The symmetrical breaking current at time t
- I_k'' = The initial short-circuit current
- μ = Decrement factor to time t defined as:

$$\begin{aligned} \mu &= 0.84 + 0.26e^{-0.26r}, & \text{for } t_{\min} &= 0.02 \text{ s} \\ \mu &= 0.71 + 0.51e^{-0.30r}, & \text{for } t_{\min} &= 0.05 \text{ s} \\ \mu &= 0.62 + 0.72e^{-0.32r}, & \text{for } t_{\min} &= 0.10 \text{ s} \\ \mu &= 0.56 + 0.94e^{-0.38r}, & \text{for } t_{\min} &\geq 0.25 \text{ s} \end{aligned} \quad (12.22)$$

In Equation (12.22), r is the ratio of the short-circuit current at the terminals of the generator $I''K_G$, to the rated generator current I_{KG} . If this ratio is less than 2, the factor μ is taken to be equal to 1 for all parting times. Interpolation can be used to predict the decrement factor μ for times other than the tabulated ones. Equation (12.22) applies to turbo alternators, salient pole generators and synchronous compensators excited by either rotating or static converters (converters with a minimum time delay of less than 0.25 seconds and with maximum excitation voltage not exceeding 1.6 times the corresponding rated load voltage). For all other cases, μ is to be taken as 1.0. If the fault is fed by more than one synchronous generator in parallel, the total breaking current is the sum of the individually contributed breaking currents. For a fault fed by several generators in a meshed network, as a first approximation, lack of AC decrement can be assumed by stipulating that the breaking current is equal to the initial short-circuit current. The

calculation is thus reduced, to calculating the initial short-circuit current I_k at the fault location of interest. An alternative calculation technique, entails extending the notions of AC decrement modeling, applied for faults at terminals, by considering machine proximity to the fault (see IEC 909:1988, 12.2.4.3).

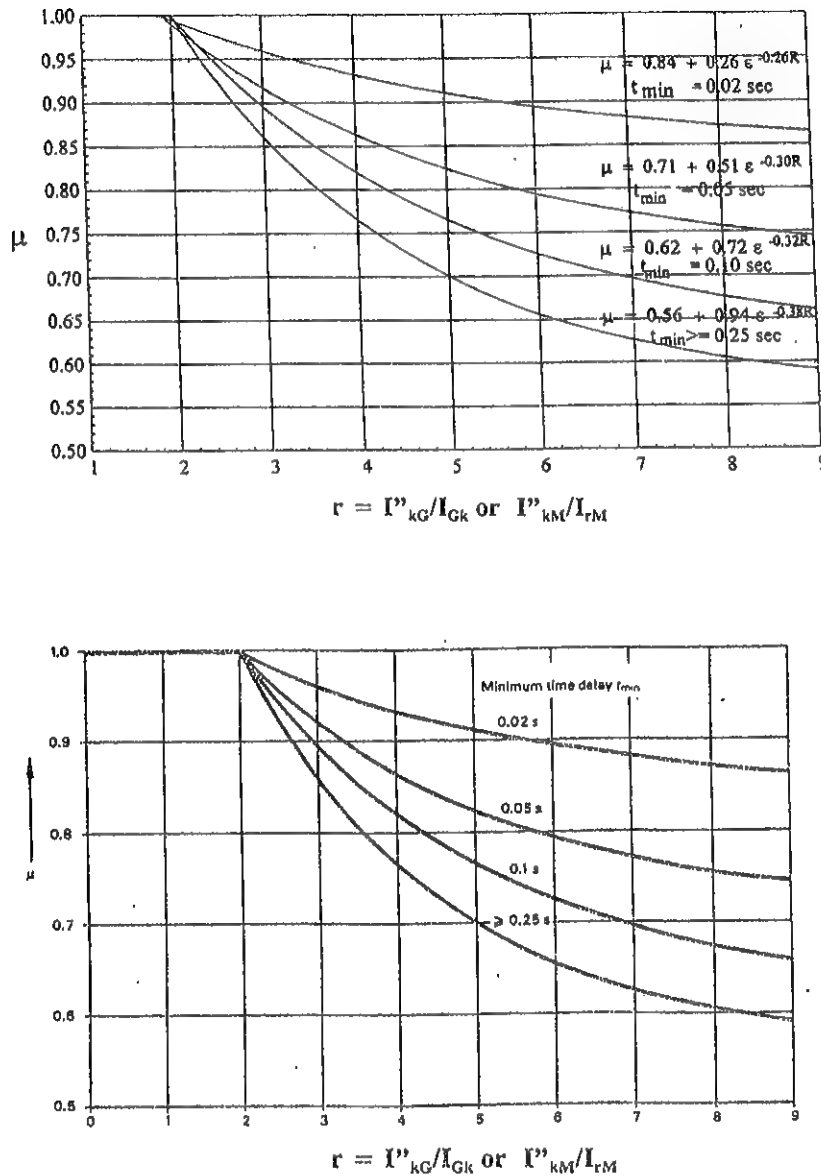


Figure 12-8—Factor μ for the calculation of short-circuit breaker current I_b

12.6.8 Steady-state fault currents calculation

Steady-state fault current estimates depend on machine synchronous reactances, saturation influences, effectiveness of voltage regulation, and maximum excitation voltage. Note that the procedures given below are considered reasonably accurate for the case of one generator supplying the short circuit. Normally, the steady-state fault current is of less magnitude than the initial and/or the breaking currents. However, when several generators are present in the system, one should always be mindful of the possibility that one or more machines may fall out of step during a sustained short circuit. In extreme cases, the steady-state fault current may, in fact, turn out to be of a magnitude higher than the initial short-circuit current. The same procedures can be applied to the case of a synchronous motor feeding the fault, assuming that the motor excitation system is independently fed. The steady-state short-circuit current, if the fault is fed from a meshed network, can be taken to be equal to the initial short-circuit current, with the motor contributions neglected (see IEC 909:1988).

12.6.9 Maximum steady-state fault current, I_{kmax}

$$I_{kmax} = \lambda_{max} I_{rG} \quad (12.23)$$

where

I_{kmax} = The maximum steady-state fault current

λ_{max} = Scaling coefficient

I_{rG} = Generator rated current

This is the steady-state fault current, furnished by a generator, for a fault at its terminals, taking into account voltage regulator action and is calculated as follows:

The maximum steady-state fault current is related to the generator rated current by virtue of its thermal effects. Since synchronous reactances and excitation systems are quite different in turbo alternators and salient pole machines, the scaling coefficient max depends on

- a) Whether the machine is of turbo or salient-pole construction and
- b) The maximum possible excitation voltage produced by the excitation system

12.6.10 Maximum steady-state fault current, I_{kmin}

This current, being of interest to the selection and setting of protective devices is the steady-state fault current provided by the generator, for a fault at its terminals, when constant no load excitation is assumed under no voltage regulator action, and is calculated as follows in Equation (12.24):

$$I_{kmin} = \lambda_{min} I_{rG} \quad (12.24)$$

where

- I_{kmin} = The minimum steady-state fault current
- λ_{min} = Scaling coefficient
- I_{rG} = Generator rated current

The scaling coefficient λ_{min} depends only on whether the machine is of the turbo alternator or salient-pole construction.

12.6.11 Coefficients λ_{max} , λ_{min}

The values of the coefficients λ_{max} and λ_{min} are obtained from the curves shown in Figure 12-9 and Figure 12-10. Two groups of curves are provided, one group for turbo alternators and another group for salient-pole machines. In turn, every group contains two sets of curves the “Series 1” set and the “Series 2” set. The curves for Series 1 λ_{max} are based on the highest possible excitation-voltage, referred to the excitation voltage at rated operation (rated current under rated power factor. They are derived for 1.3 times the rated excitation for turbo alternators and 1.6 times the rated excitation for salient pole machines (see IEC 909:1988). The curves for Series 2 λ_{max} are based on the highest possible excitation-voltage, again referred to the excitation voltage at rated operation. They are derived for 1.6 times the rated excitation for turbo alternators and 2.0 times the rated excitation for salient pole machines (see IEC 909:1988).

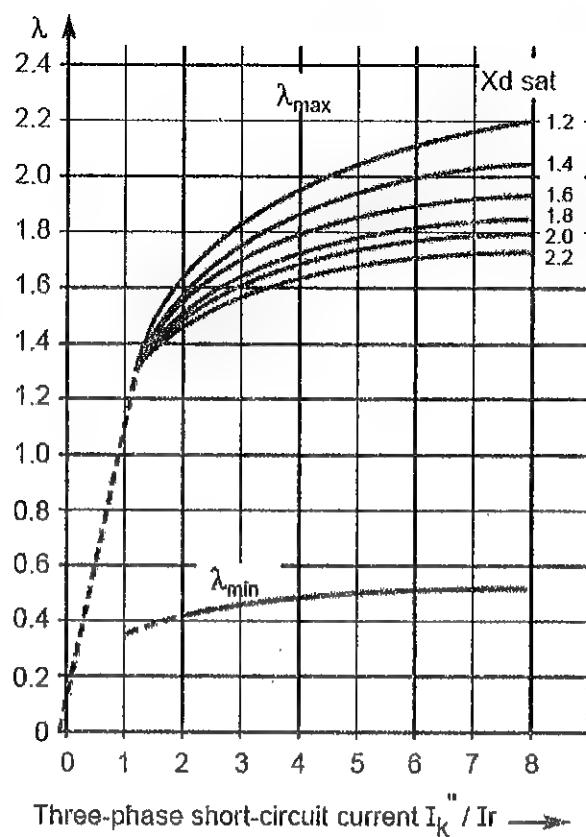


Figure 12-9—Factors λ_{\max} and λ_{\min} for turbo alternators

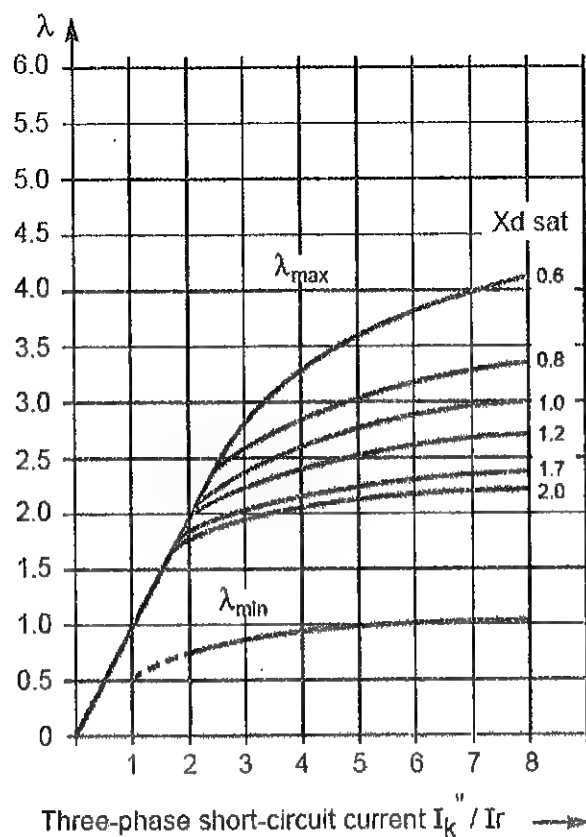


Figure 12-10—Factors λ_{max} and λ_{min} for salient pole machines

12.7 Influence of motors

12.7.1 General considerations

For faults near generator, motor contributions are to be considered when calculating the short-circuit currents. Asynchronous motor plant contributions, for a given fault location, can be neglected if the rated current of the contributing motor(s) does not exceed 1% of the fault current, calculated without considering any motors (see IEC 909:1988). These considerations rest on quantifying induction motor contributions and apply to either directly connected motors or to motors connected through transformers. Note that these considerations do not, generally, apply to three winding transformers (see IEC 60909-0:2001, IEC 909:1988). In what follows, calculation techniques for induction and synchronous motor contributions are briefly discussed.

12.7.2 Synchronous motors

Synchronous motors and synchronous compensators are to be treated as synchronous generators, when calculating the initial and peak short-circuit currents. For the case of the steady-state fault currents, this is applicable only if the synchronous motors' exciters are not bus-fed. The same will apply to synchronous compensators. When breaking currents are calculated, synchronous motor AC decrement is quantitatively modeled as in generators [see Equation (12.21)]. The ratio r is, however replaced by the ratio m , which in this case is the ratio of the short-circuit current at the terminals of the motor I'_{rm} to the rated motor current I_{rm} .

12.7.3 Induction motors

The locked rotor impedance $Z_m = R_m + jX_m$ of induction motors is given by Equation (12.25):

$$Z_m = \frac{1.0 \times U_{rm}}{I_{lr}/I_{rm} \times I_{rm} \sqrt{3}} = \frac{1.0 \times U_{rm}^2}{I_{lr}/I_{rm} \times S_{rm}} \quad (12.25)$$

where

- U_{rm} = Motor rated voltage
- I_{rm} = Motor rated current
- I_{lr} = Motor locked rotor current
- S_{rm} = Motor rated apparent power

As in the case of synchronous generators, the following X/R ratios are used to account for both AC and DC decrement of the asynchronous motor contributions:

$$X_m/R_r = 10.0 \text{ with } X_m = 0.995 Z_m \quad (12.26)$$

For high-voltage motors with power per pair of poles higher or equal to 1 MW.

$$X_m/R_r = 6.667 \text{ with } X_m = 0.995 Z_m$$

For high-voltage motors with power per pair of poles less than 1 MW.

$$X_m/R_r = 2.381 \text{ with } X_m = 0.922 Z_m$$

For low-voltage motors with connection cables.

When calculating the initial and peak short-circuit currents, asynchronous motors must be considered. Asynchronous motors are to be ignored when calculating steady-state fault currents. For breaking current calculations, however, an additional decrement factor is introduced to account for the rapid flux decay associated with faults at the terminals, as follows in Equation (12.27):

$$X_m/R_r = 6.667 \text{ with } X_m = 0.995 Z_m \quad (12.27)$$

where

- I_{bm} = The symmetrical breaking current at time t
 I'_{km} = The initial short-circuit current
 μ = Decrement factor to time t defined as per Equation (12.22)
 q = Decrement factor to time defined as follows:

$$X_m/R_r = 2.381 \text{ with } X_m = 0.922 Z_m$$

In Equation (12.27), m is the rated active power in MW of the asynchronous motor per pair of poles. The maximum value of factor q can attain is 1.00.

The principle of superposition applies to the partial initial, peak and breaking currents contributed by parallel motors at the common connection point.

12.7.4 Static drives

Static fed regenerative SCR drives are modeled as asynchronous motors with

- Z_m = According to Equation (12.25)
 U_{rm} = Converter transformer rated voltage on network side or
Drive rated voltage in the absence of transformer.
 I_{rm} = Converter transformer rated current (network side) or
Drive rated current in the absence of transformer.
 $I_{lr} / I_{rm} = 3.0$ and $X_m/R_m = 10.0$ with $X_m = 0.995 Z_m$

12.8 Fault calculations in complex systems

In the preceding sections, fault current calculation techniques and methodologies were outlined for several generic system topologies. When carrying out calculations for a more complex system, a combination of the above cases is, generally, encountered. For instance, the short-circuit current may contain not only generator and network feeder contributions, but also substantial motor (synchronous and asynchronous) content with varying degrees of electrical proximity to the fault location. The situation may be further complicated, from a topology point of view, by the fact that several of these sources may feed the fault through a network portion, comprising many branches, while others may be directly connected to the short-circuit location. Generally speaking, a combination of the above stated computational techniques should be used to avoid relaxing several rather binding clauses of the IEC 909 standard.

12.9 Comparing the ANSI-approved standards with IEC 909

By describing the salient aspects of the IEC 909 standard, one can clearly see that it departs considerably from its ANSI-approved counterpart, both conceptually and computational (Rodolakis [B3]). In trying to encapsulate the salient differences, the following can be concluded:

- 1) AC decrement modeling is conceptually and computationally different in the two standards. ANSI favors a universal machine reactance adjustment for calculating

the symmetrical interrupting currents. These multipliers are independent of fault location and breaker parting time. IEC 909:1988 can recommend, instead, taking into account machine proximity to the short circuit and explicit inclusion of the parting time.

- 2) DC decrement modeling is conceptually and computationally different in the two standards. ANSI favors a single approach, based on the X/R ratio at the fault point featuring separate reactance and resistance reductions of the faulted network. IEC 909 makes a distinction whether independent or not sources feed the fault and recommends, among other alternative techniques, complex network reductions whenever a single X/R ratio is to be used.
- 3) Steady-state fault current calculations are different in the two guidelines due to the fact that IEC requires explicit consideration of synchronous machinery excitation systems and saturation influences.

These generic differences in system modeling and computational requirements render the IEC 909 standard more computationally-intensive than its ANSI-approved counterpart. To be sure, differences are to be expected, with the IEC 909 standard exhibiting the trend to be more conservative. If computer simulations are to be performed, the different computational techniques and data base requirements of the two standards makes it necessary to use dedicated software.

12.10 Sample calculations

In what follows, the computational and modeling principles outlined in this chapter, are used to compute three-phase fault currents. The sample system used in Chapter 9, with all possible sources of short-circuit currents, shall be used for uniformity and ease of reference. Short circuits on buses 4: MILL-2 (a generator bus), 8: FDRL (a bus with a synchronous motor) and 37: T14SEC (a bus with induction motors of mixed extraction) will be simulated. An operating frequency of 60 Hz is assumed. Furthermore, negative sequence impedances for all rotating plant were assumed to be identical to the positive sequence impedances.

12.10.1 Rotating equipment impedances

12.10.1.1 Network feeders

There is only one utility service entrance point at 69 kV, situated at bus 100: UTIL-69, with a fault level of 1000 MVA and an X/R ratio of 22.2. Assuming a 10 MVA power base for the system, the impedance of the network feeder, per Table 12-1 and Equation (12.1) is:

$$Z_Q = \frac{CV_{nQ}^2}{S_Q''} = \frac{1.1 \times 69^2}{1000}$$

or

$$Z_{Qpu} = \frac{\text{Ohms} \times S_{Base}}{V_{nQ}^2} = \frac{5.2371 \times 10}{69^2} = 0.00494 + j0.010988 \text{ pu}_{10}$$

Generators at buses 4:MILL-2 and 50:GEN1 have rated voltages of 13.8 kV. Since they are both rated below 100 MVA, their respective resistances will be defaulted to 7% of their respective subtransient reactance (see 12.6.3). Thus,

$$X_g = 0.128 \text{ pu}_{12.5}, R_g = 0.07 \times 0.128 = 0.00896 \text{ p.u.}_{12.5}, \text{ for the generator at 4: MIL-2}$$

$$X_g = 0.112 \text{ pu}_{15.625}, R_g = 0.07 \times 0.112 = 0.00784 \text{ p.u.}_{12.5}, \text{ for the generator at 50: GEN1}$$

Furthermore, since the generators are directly connected to the system (no unit transformer), the impedance correction factors per 12.6.3 and Equation (12.16) will apply. The rated power factor for both generators is 0.85. Thus,

$$K_o = \frac{V_c C_{MAX}}{U_{rG}(1.0 + X_d'' \sin(\phi_{rG}))} = \frac{13.8 \times 1.1}{13.8(1.0 + 0.128 \times 0.6)} = \frac{1.1}{1.0768} =$$

1.02154 at MILL-2

$$K_o = \frac{V_c C_{MAX}}{U_{rG}(1.0 + X_d'' \sin(\phi_{rG}))} = \frac{13.8 \times 1.1}{13.8(1.0 + 0.112 \times 0.6)} = \frac{1.1}{1.0672} =$$

1.03073 at GEN1

Based on the above considerations, the generator impedances that are to be used for short-circuit calculations, in p.u. of their respective MVA base are:

$$Z_G = 1.02154 \times (0.00896 + j 0.128) = 0.009153 + j0.13076 \text{ p.u.}_{12.5}, \text{ at 4: MILL-2,}$$

and

$$Z_G = 1.03073 \times (0.00784 + j 0.112) = 0.008081 + j0.11544 \text{ p.u.}_{15.625}, \text{ at 50: GEN1}$$

12.10.1.2 Synchronous motors

For the 9000 HP synchronous motor at bus 8:FDRL, with a subtransient reactance of 20%, the impedance (per section 12.6.2 with $R = 7\%$) is:

$$Z_{sin} = 0.07 \times 0.20 + j0.20 = 0.014 + j 0.020 \text{ in p.u. on the motor base of 9 MVA.}$$

12.10.1.3 Induction motors

Consider as an example bus 37:T14SEC. There is an induction motor of 700 HP (678.8 kVA) and a total combined motor load of 300 HP (300 kVA) composed of motors

rated less than 50 HP. 10 motors, each rated 30 kVA were assumed. All motors run at 1800 rpm, which for a 60 Hz system amounts to two pairs of poles.

For the 700 HP motor the impedance magnitude is calculated as $Z_m = (0.0139 + j0.167) = 0.1676$ p.u. on motor base parameters. Thus, converting to the impedance per the IEC procedures in section 12.6.3, the motor impedance becomes:

$$Z_m = (0.922 \times 0.1676/2.381 + j0.1676 \times 0.922) = 0.0649 + j0.1545 \text{ p.u.}_{0.6788}$$

Similarly for one 30 HP motor, the impedance magnitude is $Z_m = (0.0334 + j0.167) = 0.1703$ p.u. on motor base parameters. Thus, according to 12.7.3, the motor impedance becomes:

$$Z_m = (0.922 \times 0.1703/2.381 + j0.1703 \times 0.922) = 0.0659 + j0.1570 \text{ p.u.}_{0.03}$$

The induction motor impedances, for the entire network, were modified per 12.7.3 and the subclauses that follow depict selected computer-generated results.

12.10.2 Calculation of maximum initial fault currents

12.10.2.1 Fault at bus 4:MILL-2

The equivalent complex impedance at bus 4:MILL-2 is:

$$Z_{QQ} = 0.00277 + j0.2983 = 0.2996 \text{ pu}_{10}$$

The total initial fault current is calculated Equation (12.1) is:

$$I_k'' = \frac{C_{max} V_{npu}}{Z_{QQ}} = \frac{1.1 \times 1.0}{0.02996} = 36.71 \text{ pu}_{10} \text{ I, or } = 15.36 \text{ kA}$$

The MILL-2 generator contribution amounts to:

$$I_{kG}'' = \frac{C_{max} V_{npu}}{Z_{KG}} = \frac{1.1 \times 1.0}{0.10486} = 10.49 \text{ pu}_{10} \text{ I, or } \frac{10.49 \times 10}{13.8\sqrt{3}} = 4.39 \text{ kA}$$

12.10.2.2 Fault at bus 8:FDRL

The equivalent system impedance at bus 8:FDRL was calculated to be $Z_{QQ} = 0.033 + j0.0305 = 0.03068$ p.u. on a 10 MVA base. The initial fault current is calculated to be:

$$I_k'' = \frac{C_{max} V_{npu}}{Z_{QQ}} = \frac{1.1 \times 1.0}{0.03068} = 35.856 \text{ pu}_{10} \text{ I, or } \frac{35.856 \times 10}{13.8\sqrt{3}} = 15.0 \text{ kA}$$

with a synchronous motor contribution of

$$I'_{kG} = \frac{C_{max} V_{npu}}{Z_{KG}} = \frac{1.1 \times 1.0}{0.022277} = 4.938 \text{ pu}_{10} \text{ I, or } \frac{4.938 \times 10}{13.8\sqrt{3}} = 2.07 \text{ kA}$$

12.10.2.3 Fault at bus 37:T14SEC

The equivalent complex system impedance at bus 37:T14SEC (low-voltage bus) is:

$$Z_{QQ} = 0.1052 = j0.4386 = 0.45104 \text{ pu}_{10}$$

The initial fault current is calculated to be:

$$I'_k = \frac{C_{max} V_{npu}}{Z_{QQ}} = \frac{1.05 \times 10}{0.045104} = 2.33 \text{ pu}_{10} \text{ I, or } \frac{2.33 \times 10}{0.48\sqrt{3}} = 28.0 \text{ kA}$$

The 700 HP (0.68MVA) induction motor contribution amounts to:

$$I'_{kM1} = \frac{C_{max} V_{npu}}{Z_{KM2}} = \frac{1.05 \times 10}{2.4686} = 0.4253 \text{ pu}_{10} \text{ I, or } \frac{0.4253 \times 10}{0.48\sqrt{3}} = 5.116 \text{ kA}$$

The induction motor contribution from the 10 30HP motors is:

$$I'_{kM2} = \frac{C_{max} V_{npu}}{Z_{KM2}} = \frac{1.05 \times 10}{5.6743} = 0.185 \text{ pu}_{10} \text{ I, or } \frac{0.185 \times 10}{0.48\sqrt{3}} = 2.22 \text{ kA}$$

Despite the fact that an almost step-by-step approach was taken here to illustrate the calculating techniques, hand calculations remain quite tedious particularly in view of data preparation procedures and the complex network reduction requirements. Computer programs are available today that automate these calculations and provide important additional side benefits such as, data validation, defaulting the source impedances for proper dc decrement purposes, automatic application of the relevant correction factors, and system-wide assessment of the calculated fault contributions.

12.10.3 Calculation of peak fault currents

Let us consider bus 4:MILL-2, a high-voltage bus with a synchronous generator. The procedures outlined below are directly applicable to bus 8:FDRL, where the synchronous motor is connected. The total peak fault current at MILL-2 can be calculated as the sum of the generator peak fault current and the system peak fault current (see 12.5.6). The equivalent system impedance at bus MILL-2, without the generator is, $Z_s = 0.0043 + j0.0417 = 0.04193 \text{ pu}_{10}$. Thus the partial system peak current will be calculated according to the following crest factor, per Equation (12.11) and Equation (12.12).

$$\kappa_b = 1.15 \kappa_a = 1.15(1.02 + e^{-3(0.0043/0.0417)}) = 2.00$$

The initial short-circuit current from the system is therefore,

$$I''_{ks} = C_{\max} V_{npu} / Z_{qqs} = 1.1 \times 1.00 / 0.04193 = 26.235 pu_{10}, \text{ or } 26.235 \times 10 / (13.8\sqrt{3}) = 10.97 \text{ kA}$$

Using the above calculated crest factor, per 12.5.3, we obtain

$$I_{ps} = \kappa_b \sqrt{2} I''_{ks} = 2.00 \sqrt{2} 10.97 = 31.03 \text{ kA}$$

Similarly, the generator crest factor will be:

$$\kappa_{GEN} = 1.02 + 0.98 e^{-3 \times 0.07} = 1.8143$$

$$I'_{kG} = \frac{C_{\max} V_{npu}}{Z_{KG}} = \frac{1.1 \times 1.0}{0.10486} = 10.49 pu_{10} \text{ I, or } \frac{10.49 \times 10}{13.8\sqrt{3}} = 4.39 \text{ kA}$$

resulting in a peak current of:

$$I_{PGEN} = \kappa_{GEN} \sqrt{2} I'_{GEN} = 1.8143 \sqrt{2} \times 4.39 = 11.26 \text{ kA}$$

The total peak current at bus 4:MILL-2 is therefore, $31.03 + 11.26 = 42.29 \text{ kA}$.

12.10.4 Calculation of breaking currents

12.10.4.1 Fault at bus 8:FDRL

A three-phase fault is considered at bus 8:FDRL. Assume that the breaking time is 0.02 s (1.2 cycles). The total breaking current will be composed of the symmetrical rms breaking current and the unidirectional DC component.

The symmetrical breaking current at bus FDRL is composed of the symmetrical breaking current of the synchronous motor and of the symmetrical breaking current contributed from the rest of the system. Assuming no AC decrement for the system contribution, the breaking current is the initial short-circuit current at bus 8:FDRL with the synchronous motor disconnected.

The initial fault current is calculated to be:

$$I_{bS} = \frac{C_{\max} V_{npu}}{Z_{QQ}} = \frac{1.1 \times 1.0}{0.03559} = 30.9055 pu_{10} \text{ I, or } \frac{30.9055 \times 10}{13.8\sqrt{3}} = 12.93 \text{ kA}$$

This current has a DC component of:

$$I_{dcs} = \sqrt{2} I''_{kS} e^{-2\pi f R / X} = \sqrt{2} \times 12.93 \times 0.42 = 7.695 \text{ kA}$$

The synchronous motor contributes a symmetrical breaking current, which is calculated as follows (see 12.6.7):

Since $r = I''_{km}/I_{rm} = 2066/376.53 = 5.487$, the decrement factor for a 0.02 s (1.2 cycle) parting time per Equation (12.12) is as follows:

$$\mu = 0.84 + 0.26e^{-0.26r} = 0.84 + 0.26e^{-0.26 \times 5.487} = 0.902$$

yielding a breaking current of [Equation (12.21)] $I_{bM} = \mu I''_{kM} = 2.066 \times 0.902 = 1.864$ kA, with a DC component amounting to the following:

$$I_{dcs} = \sqrt{2} I''_{kM} e^{-2\pi f R/X} = \sqrt{2} \times 2.066 \times 0.5899 = 1.724 \text{ kA}$$

Thus the total symmetrical breaking current at the bus 8:FDRL will be as follows:

$$I_b = I_{bS} + I_{bM} = 12.9 \text{ kA} + 1.724 \text{ kA} = 14.65 \text{ kA}$$

12.10.4.2 Fault at bus 37:T14SEC

The calculation of the total breaking current for bus 37:T14SEC follows the same procedure as for bus 8:FDRL. For illustration purposes, however, only the symmetrical breaking currents contributed by the two induction motors will be calculated for a breaking time of 0.05 s (3 cycles).

For the 700 hp 1800 rpm induction motor using Equation (12.27),

$$m = \text{HP} \times 0.746 \times \text{MW/HP} / (1000 \times \text{HP} \times \# \text{ pole pairs}) = 700 \times 0.746 / (1000 \times 2) = 0.261 \text{ MW /pole pair}$$

$$\text{and factor } q = 0.79 + 0.12 \ln(m) = 0.79 + 0.12 \ln(0.261) = 0.6288$$

Since $r = I''_{km}/I_{rm} = 5116/816.47 = 6.26589$, the decrement factor for a 0.05 s (3 cycles) parting time is:

$$\mu = 0.71 + 0.51e^{-0.3r} = 0.71 + 0.51e^{-0.3 \times 6.26589} = 0.7878$$

and the 700 hp motor symmetrical breaking current given by Equation (12.26) is:

$$I_{bM} = \mu q I''_{kM} = 0.7878 \times 0.6288 \times 5.116 = 2.535 \text{ kA}$$

Similarly, for the 10 smaller 30 HP, 1800 rpm motors, the following is obtained:

$$m = \text{HP} \times 0.746 \times \text{MW/HP} / (1000 \times \text{HP} \times \# \text{ pole pairs}) = 30 \times 0.746 / (1000 \times 2) = 0.011 \text{ MW /pole pair}$$

$$\text{and factor } q = 0.79 + 0.12 \ln(m) = 0.79 + 0.12 \ln(0.011) = 0.2508$$

Since $r = I''_{km}/I_{rm} = 2225/360.8 = 6.167$, the decrement factor for a 0.05 s (3.0 cycle) parting time is:

$$\mu = 0.71 + 0.51e^{-0.3r} = 0.71 + 0.51e^{-0.3 \times 6.167} = 0.7902$$

and the 10–30 hp motor symmetrical breaking current given by Equation (12.26) is as follows:

$$I_{bM} = \mu q I''_{kM} = 0.7902 \times 0.6288 \times 2.225 = 0.441 \text{ kA}$$

12.10.5 Calculation of steady-state generator fault currents

Consider the Generator at 4:MILL-2. Assume there is a fault at 4:MILL-2 and that we are interested in calculating the steady-state fault current contributed by the generator GEN2. Assuming a saturated reactance of 1.2 p.u. on the generator basis and taking into account the fact that the generator is of the turbo-alternator type, the following is obtained:

$$I_r = \frac{MVA}{\sqrt{3}kV} = \frac{12.5}{\sqrt{3} \times 13.8} = 0.523 \text{ kA} \quad \begin{aligned} I_r &= MVA/(\sqrt{3}kV) = 12.5/\sqrt{3} \times 13.8 = 5.523 \text{ kA} \\ r &= I''_{kG}/I_{rG} = 4389/523 = 8.392 \end{aligned}$$

$$r = \frac{I''_{kG}}{I_{rG}} = \frac{4389}{523} = 8.392$$

From the Curves of Series 1 (turbo) of the IEC 909:1988 (12.2.1.4) we obtain, $\lambda_{\max} = 2.20$ for a steady-state fault current from Equation (12.23) of:

$$I_{k\max} = \lambda_{\max} I_{rG} = 2.20 \times 0.523 = 1.15 \text{ kA}$$

From the Curves of Series 2 (turbo) of the IEC 909 (12.2.1.4), we obtain, $\lambda_{\max} = 2.70$ for a steady-state fault current of:

$$I_{k\max} = \lambda_{\max} I_{rG} = 2.70 \times 0.523 = 1.412 \text{ kA}$$

12.11 Normative references

The following referenced documents are indispensable for the application of this document. For dated references, only the edition cited applies. For undated references, the latest edition of the referenced document (including any amendments or corrigenda) applies.

IEC 909:1988, Short-Circuit Current Calculation in three-phase a.c. systems. International Standard (IEC), first edition.²

²IEC publications are available from the Sales Department of the International Electrotechnical Commission, Case Postale 131, 3, rue de Varembé, CH-1211, Genève 20, Switzerland/Suisse (<http://www.iec.ch/>). IEC publications are also available in the United States from the Sales Department, American National Standards Institute, 11 West 42nd Street, 13th Floor, New York, NY 10036, USA.

IEC 60909-0:2001, Short-circuit currents in three-phase systems—Part 0: calculation of currents.

IEC 61362-1:1998, Guide to specification of hydraulic turbine control systems.

IEC 61363-1:1998, Electrical installations of ships and mobile and fixed offshore units—Part 1: Procedures for calculating short-circuit currents in three-phase ac.

12.12 Bibliography

[B1] IEC 60038: 1994, IEC standard voltages, Amendment 1.

[B2] IEC 781:1991, Application guide for calculation of short-circuit currents in low-voltage systems. International Standard (IEC), first edition, 1989.

[B3] Rodolakis, A. J., "A comparison of North American (ANSI) and European (IEC) Fault Calculation Guidelines," *IEEE Transactions on Industry Applications*, Vol. 29, No. 3, pp. 515–521, May/June 1993.

[B4] Roeper, R., *Short-Circuit Currents in Three-Phase Systems*. Siemens Actiengesellschaft, John Wiley and Sons, 1985.

